DEVELOPMENT OF A LOW NO_X BURNER SYSTEM FOR COAL FIRED POWER PLANTS USING COAL AND BIOMASS BLENDS

A Thesis

by

PATSKY ORIDEL GOMEZ

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2009

Major Subject: Mechanical Engineering

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Approved by:

Chair of Committee,	Kalyan Annamalai
Committee Members,	Sergio C. Capareda
	Timothy J. Jacobs
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ABSTRACT

Development of a Low NO_x Burner System for Coal Fired Power Plants

Using Coal and Biomass Blends. (May 2009)

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The low NO_x burner (LNB) is the most cost effective technology used in coal-fired power plants to reduce NO_x. Conventional (unstaged) burners use primary air for transporting particles and swirling secondary air to create recirculation of hot gases. LNB uses staged air (dividing total air into primary, secondary and tertiary air) to control fuel bound nitrogen from mixing early and oxidizing to NO_x; it can also limit thermal NO_x by reducing peak flame temperatures. Previous research at Texas A&M University (TAMU) demonstrated that cofiring coal with feedlot biomass (FB) in conventional burners produced lower or similar levels of NO_x but increased CO. The present research deals with i) construction of a small scale 29.31 kW (100,000 BTU/hr) LNB facility, ii) evaluation of firing Wyoming (WYO) coal as the base case coal and cofiring WYO and dairy biomass (DB) blends, and iii) evaluating the effects of staging on NO_x and CO.

Ultimate and Proximate analysis revealed that WYO and low ash, partially composted, dairy biomass (LA-PC-DB-SepS) had the following heat values and empirical formulas: $CH_{0.6992}N_{0.0122}O_{0.1822}S_{0.00217}$ and $CH_{1.2554}N_{0.0470}O_{0.3965}S_{0.00457}$. The

WYO contained 3.10 kg of Ash/GJ, 15.66 kg of VM/GJ, 0.36 kg of N/GJ, and 6.21 kg of O/GJ while LA-PC-DB-SepS contained 11.57 kg of Ash/GJ, 36.50 kg of VM/GJ, 1.50 kg of N/GJ, and 14.48 kg of O/GJ.

The construction of a LNB nozzle capable of providing primary, swirled secondary and swirled tertiary air for staging was completed. The reactor provides a maximum residence time of 1.8 seconds under hot flow conditions. WYO and DB were blended on a mass basis for the following blends: 95:5, 90:10, 85:15, and 80:20. Results from firing pure WYO showed that air staging caused a slight decrease of NO_x in lean regions (equivalence ratio, $\phi \leq 1.0$) but an increase of CO in rich regions ($\phi=1.2$). For unstaged combustion, cofiring resulted in most fuel blends showing similar NO_x emissions to WYO. Staged cofiring resulted in a 12% NO_x increase in rich regions while producing similar to slightly lower amounts of NO_x in lean regions. One conclusion is that there exists a strong inverse relationship between NO_x and CO emissions.

DEDICATION

This thesis is dedicated to my parents, Charles and Noemi Caraballo, for all of their love, hard work and encouragement throughout the years and to my wife, Mitzi, who has provided me with unconditional love and support throughout all of my personal and professional endeavors.

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. Annamalai, for his mentorship, guidance, and patience. I am grateful for having the opportunity to conduct this research under his supervision and to learn from his extensive knowledge in the field of combustion. I would also like to thank my committee members, Dr. Capareda and Dr. Jacobs, for their guidance and support throughout the course of this research.

I would like to also thank all of the graduate students in the Coal and Biomass Energy Laboratory at Texas A&M University who took the time to teach me the fundamentals of combustion, helped me complete construction of the LNB furnace, provided me with guidance and advice on how to conduct my experiments and write my thesis, and reviewed my final thesis report. Without their guidance, personal involvement, and support, I would not have been as successful in completing this research. I would personally like to thank Ben Lawrence for acting as one of my mentors during this process as well as Gerardo Gordillo, Hyukjin Oh, Nicholas Carlin, and Uday Sarathy. I would like to specifically recognize and thank Jason Wayne Caswell in the physics department's electronic shop here at Texas A&M for not only assisting me in setting up the gas flow meters and thermocouples for the LNB furnace but for also writing the LabVIEW program used for this research. I also want to extend my gratitude to the Sun Grant Foundation, which provided the funding to make this research possible.

Finally, I want to thank my family for always giving me the tools necessary for me to succeed in life and for pointing out what really matters in life. I would like to thank my wife, Mitzi, for always standing by my side and to my daughter, Kylee, and son, David, for being such wonderful children. I love you all.

NOMENCLATURE

AOFA	Advanced Overfire Air
AR	Advanced Reburning
ARP	Acid Rain Program
BTU	British Thermal Unit
^{o}C	Degrees Celsius
C	Carbon
CAFO	Combined Animal Feeding Operation
CAIR	Clean Air Interstate Rule
CAMD	Clean Air Market Division
CB	Cattle Biomass
CBEL	Coal and Biomass Energy Laboratory
CEM	Continuous Emission Monitoring
CH	Hydrocarbons
CH_4	Natural Gas
CFM	Cubic Meters Per Minute
CO	Carbon Monoxide in Exhaust Gas Stream
CO_2	Carbon Dioxide in Exhaust Gas Stream
CP/UPA	Cooperative Power/United Power Association
Cp	Specific Heat Capacity
DAF	Dry Ash Free

DB	Dairy Biomass
DOE	U.S. Department of Energy
E	Energy
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
EPRI	Electrical Power Research Institute
FC	Fixed Carbon
FWEC	Foster Wheeler Energy Corporation
^{o}F	Degrees Fahrenheit
g	Grams
GJ	Gigajoule
GPC	Georgia Power Company
H	Hydrogen
h	Enthalpy
HA-PC-DB-SoilS	High Ash Partially Composted Dairy Biomass Soil Surfaced Pens
HCN	Hydrogen Cyanide
HHV	Higher Heating Value
$(HOCN)_3$	Cyanuric Acid
hr	Hour
IRZ	Internal Recirculation Zone
K	Kelvin
kg	Kilogram

kJ	Kilojoule
kW	Kilowatt
LA-PC-DB-SepS	Low Ash Partially Composted Dairy Biomass Separated Solids
lb	Pound
LPM	Liters Per Minute
LNB	Low NO_x Burner
OFA	Overfire Air
MW	Megawatt
M_k	Molecular Weight of species k
$\dot{m}$	Mass Flow Rate
m^3	Meter Cubed
mmBTU	Million British Thermal Units
NBP	NO_x Budget Trading Program
N_2	Nitrogen
NH_2CONH_2	Urea
NH_3	Ammonia
NO_x	Nitrous Oxides in Exhaust Gas Stream
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen in Exhaust Gas Stream
$O_{2,a}$	Oxygen in Ambient Air
PA	Primary Air

PC	Pulverized Coal
PM	Particulate Matter
PPM	Parts Per Million
PVC	Polyvinyl Chloride
$\dot{Q}$	Heat Transfer Rate
r_b	Tube Radius
r_h	Hub Radius
RZ	Recirculation Zone
SA	Secondary Air
SCR	Selective Catalytic Reduction
SCFH	Standard Cubic Feet Per Hour
SepS	Separated Solids
SLMP	Standard Liters Per Minute
SMD	Sauter Mean Diameter
SMOG	Smoke and Fog
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
S	Swirl Number
T	Temperature
t	Time
TA	Tertiary Air
TAMU	Texas A&M University

TCEQ	Texas Commission on Environmental Quality
TLN	Tangential Low NO_x
TGA	Thermogravimetric Analysis
TSP	Total Suspended Particles
TXL	Texas Lignite Coal
VM	Volatile Matter
$\dot{W}$	Work rate per time (Power)
WYO	Wyoming Powder River Basin Coal
α	Blade Angle
ρ	Density
ϕ	Equivalence Ratio

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CHAPTER I

INTRODUCTION

NO_x is a byproduct of the coal combustion process and a pollutant which is harmful to the environment and people's health (EPA, 1998). Because of the hazards associated with NO_x emissions, the EPA has implemented stringent regulations to limit the amount of NO_x produced by coal-fired power plants. Manure is a waste product, which if not treated or disposed of properly, can also pollute the environment; however, it could serve as a renewable energy source. In recent years, the interest in renewable fuels has increased due to the global warming threat and current regulations which limit the amount of hazardous pollutants released into the atmosphere.

The current research focused on completing the design and construction of a low NO_x burner (LNB) furnace capable of cofiring pulverized coal with DB in order to demonstrate the effects of staged combustion and cofiring of DB on NO_x and CO emissions. This research was funded by the Sun Grant Initiative to study the use of animal waste in coal-fired plants, a biotechnology platform for biomass thermo-chemical conversion. There is currently no literature on the viability or benefits of cofiring DB in a LNB furnace. The fuels used were blended on a mass basis and cofired in a small scale 100,000 BTU/hr LNB furnace located at CBEL in TAMU.

This thesis follows the style of *Combustion Science and Technology*.

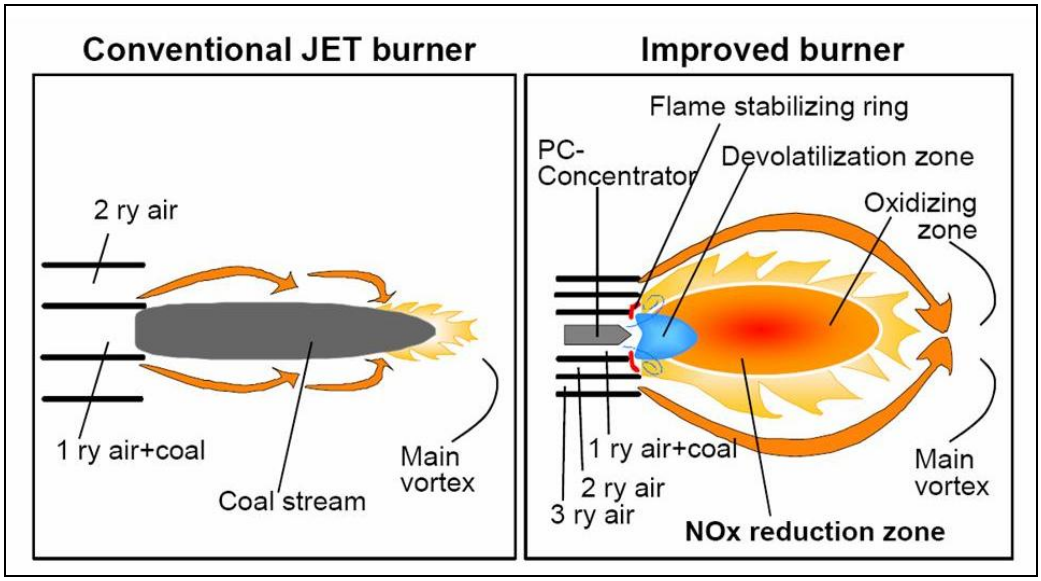

Figure 1. Comparison of conventional JET-burner with Fortum's Rapid Ignition (RI) JET-burner for tangentially fired boilers developed by Enprima. Adapted from Yano et al. (2003).

In conventional burners, coal is transported by primary air (making up approximately 15-20% of the total air) while the remaining air required to complete the combustion process is supplied by a swirling secondary air (making up approximately 80-85% of the total air) (Figure 1a). The LNB furnace stages or delays a portion of the air required for stoichiometric or complete combustion from mixing with the coal in the primary burn zone thus creating a fuel-rich zone that drives the formation of molecular nitrogen (decreasing fuel NO_x production) and maintaining a lower flame temperature (decreasing thermal NO_x production). The remaining air required for stoichiometric conditions or 100% of the theoretical air required to complete the combustion process is provided by the tertiary air and mixes with the fuel at the end of the flame front. This allows for complete combustion to occur in the secondary burn zone (Figure 1b). The

LNB consists of the following three zones: i) primary zone, ii) secondary zone along with recirculation, and iii) tertiary zone.

Wyoming coal (WYO), a subbituminous coal, was used as the baseline fuel. Low Ash (LA) Partially Composted (PC) Dairy Biomass (DB) produced via a solid separation process (SepS) in dairy farms was mixed with WYO and burned. High Ash Partially Composted Dairy Biomass taken from the Soil Surface (HA-PC-DB-SoilS) was not considered as a fuel due to the higher ash content. This high ash (HA) content accumulates ash deposits inside of the small scale furnace causing significant ash fouling and slagging problems that damage measurement devices and cause significant clogging in the gas sample ports. Goughnour (2006) demonstrated that cofiring the high ash partially composted feedlot biomass clogged the small-scale reactor entirely as shown in Figure 2.

Figure 2. Top view of slag or melted ash deposits in the furnace. Adapted from Ghounour (2006).

Unstaged pure WYO was fired in the LNB furnace with only primary and secondary air to measure base case emissions. The pure WYO was then fired at the

same equivalence ratios with the same amount of total air flow consisting of primary, swirled secondary and swirled tertiary air in order to evaluate the effect of staging on NO_x emissions and to evaluate whether or not the constructed small scale LNB furnace successfully reduced NO_x with air staging.

For this research the following WYO:DB fuel blends were examined: 95:5, 90:10, 85:15, and 80:20. The equivalence ratio (ϕ) was varied from 0.8 to 1.2 in 0.1 increments. Two sets of experiments were conducted. The first was focused on changing the air flow rate to change the equivalence ratio while maintaining a constant fuel feed rate / heat output of 100,000 BTU/hr. The second set of experiments focused on changing the fuel feed rate / heat output to change the equivalence ratio while maintaining a constant air flow. This second set of experiments was completed to replicate how an actual coal-fired power plant could maintain the same air flow rate while adjusting the coal-biomass fuel blend feed rate / heat output to achieve the desired equivalence ratio. The constant air flow was set at stoichiometric air with 80% provided by the primary and secondary air combined and 20% provided by the tertiary air. The following exhaust gases were measured and analyzed: CO_2, CO, NO_x, O_2, and C_xH_y.

A significant result found during this research was that the designed LNB furnace showed that air staging caused approximately a 12% decrease of NO_x in lean regions and approximately a 24% increase of CO at ϕ=1.2 for pure WYO. For unstaged combustion for constant fuel feed rate/heat output cases and constant air flow cases, cofiring resulted in most fuel blends showing similar NO_x emissions to WYO. Due to the uncertainty of these experiments and the large measured range of CO emissions, a

conclusion could not be determined for unstaged cofiring on CO. Staged cofiring resulted in most fuel blends producing approximately a 33% increase of NO_x in the rich regions and while producing similar to slightly lower amounts of NO_x in the lean regions. One conclusion is that there exists a strong inverse relationship between NO_x and CO emissions.

CHAPTER II

LITERATURE REVIEW

This chapter discusses NO_x and Dairy Biomass (DB) pollution and their effects on the environment. This has led to increased government regulation and development of new technologies focused on reducing NO_x emissions such as the Low NO_x burner (LNB) used in pulverized coal-fired power plants. This section also addresses the limited research available on the benefits of decreasing NO_x production by co-firing DB with pulverized coal.

NO_x POLLUTION

Coal continues to be the primary source of electricity in the United States as shown in figure 3 below. This appears to be the case for the foreseeable future due to the abundance and affordability of this fossil fuel source as compared to the higher costs and limitations of using alternative energy technologies such as hydroelectric, solar, wind and nuclear power.

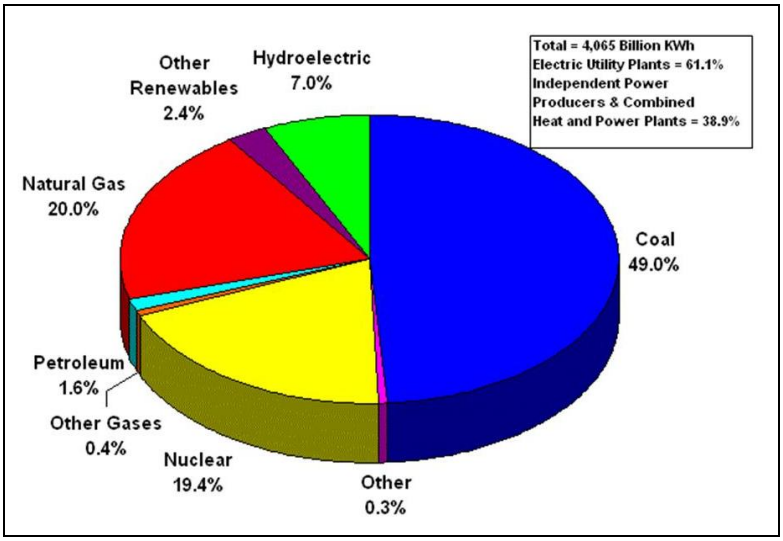

Figure 3. 2006 EPA Net Generation.
Adapted from Energy Information Administration (2006).

Since coal continues to provide the majority of electricity in the United, advancements in technology and processes used to harness this power from the combustion process need to be made in order to reduce or limit the hazardous effects of combustion. One of the major drawbacks of burning fossil fuels is the production of combustion products that have been shown to negatively impact the environment and human health. Global warming and environmental pollution has been a major issue for the current generation and will remain a challenge for future generations to come.

A major concern today is the production of NO_x which is formed during the combustion of fossil fuels. NO_x is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying molecular formations. "Among many species (NO, NO_2, NO_3, N_2O, N_2O_3, N_2O_4, N_3O_4 and mixtures thereof) which are represented as NO_x, the main species are NO and NO_2" (Kobayashi et al., 2007). NO_x is

colorless and odorless. NO_x reacts with other elements to form acid rain; reduces the quality of water by decreasing the amount of oxygen available for aquatic life; reacts with volatile organic compounds (VOC) to form ground level ozone or smog; reacts with ammonia and other substances to form nitric acid; and blocks the transmission of light. Because NO_x is a greenhouse gas, it also contributes to global warming (EPA, 1998). The following list highlights a few of the other concerns regarding NO_x emissions (EPA, 1998):

1. NO_x is one of the main ingredients in the formation of ground-level ozone, where it is not wanted due to the fact that it can trigger serious respiratory problems;
2. NO_x reacts to form nitrate particles, acid aerosols, and NO_2 which also cause respiratory problems;
3. NO_x reacts to form toxic chemicals. It can react with O_3 at high altitudes to produce NO_2 causing O_3 (ozone) depletion;
4. NO_x can be transported over long distances; therefore, NO_x pollution is a regional hazard and is not constrained to a local area.

"Grey Smog – a mixture of smoke, fog, and other chemicals, had been a recognised [*sic*] sign of air quality problems since 1911 in industrial cities like New York and London but in 1946 a new type of smog – Brown Smog – was recognised [*sic*] first in Los Angeles and later in Denver and in other major cities such as São Paulo" (Bowen et al., 1994). NO_x is formed when a HC fuel is burned at high temperatures, as in a combustion process, but it can also be formed at low temperatures for fuels

containing nitrogen such as coal. The primary sources of NO_x are motor vehicles, electric utilities, and other industrial, commercial, and residential sources that burn fuels as shown in figure 4 (EPA, 2003).

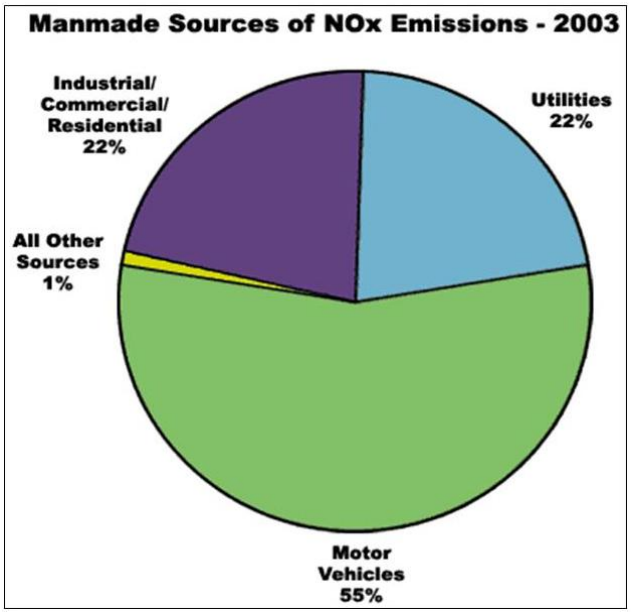

Figure 4. Manmade sources of NO_x emissions. Adapted from http://www.epa.gov/air/urbanair/nox/what.html (2003).

NO_x REGULATION

Reducing NO_x emissions is a crucial component of EPA's strategy for cleaner air. Federal and state governments are requiring more stringent emission standards to reduce NO_x emissions. The Texas Commission on Environmental Quality (TCEQ) established a NO_x emission limit for coal-fired power plants of 70.94 g/GJ (0.165 lb/mmBTU) for the regions located between Dallas-Ft. Worth and Houston-Galveston's non-attainment regions effective in 2005 (EPA, 2005a). The EPA has also passed

numerous regulations restricting the amount of NO_x being produced throughout the United States.

In January of 1993, Part 75 established Continuous Emission Monitoring (CEM) and reporting requirements under EPA's Acid Rain Program (ARP), instituted in 1990 under Title IV of the Clean Air Act (EPA, 2005c). The ARP regulates Electric Generating Units (EGU) that burn fossil fuels such as coal, oil and natural gas and that serve a generator greater than 25 MW. This program requires CEM and reporting of sulfur dioxide (SO_2) mass emissions, carbon dioxide (CO_2) mass emissions, nitrogen oxides (NO_x) emission rates, as well as the heat input.

In October of 1998, the NO_x Budget Trading Program (NBP) adopts Subpart H to Part 75 which provided a blueprint for the monitoring and reporting of NO_x mass emissions and heat input under a State or Federal NO_x emissions reduction program. The NBP is a NO_x cap and trade program designed to limit ground-level ozone formation during the ozone season (from May 1st through September 30th) in 22 states in the Eastern U.S. The program assigns a total NO_x emissions budget (tons per ozone season) to each state, and is administered jointly by the states and EPA's Clean Air Markets Division (CAMD).

In May of 2005, the Clean Air Interstate Rule (CAIR) imposed tight emission caps on NO_x mass emissions from Electric Generating Units (EGUs) in 28 states which include annual NO_x emission caps in 23 of the 28 states. CAIR will reduce NO_x emissions across 28 Eastern States and D.C. by over 60% from 2003 levels by regulating emission "allowances" for NO_x to each state. Sources are able to choose from many

compliance alternatives to include: installing pollution control equipment; switching fuels; or buying excess allowances from other sources that have reduced their emissions. The following is a timeline of the EPA's implementation plan for CAIR (EPA, 2005b):

1. 2005: Promulgate CAIR Rule
2. 2006: State Implementation Plans Due
3. 2009: Phase I Cap in Place for NO_x (1.5 million tons of annual NO_x)
4. 2015: Phase II Cap in Place for NO_x (1.3 million tons of annual NO_x)

Figure 5 illustrates the states covered by CAIR:

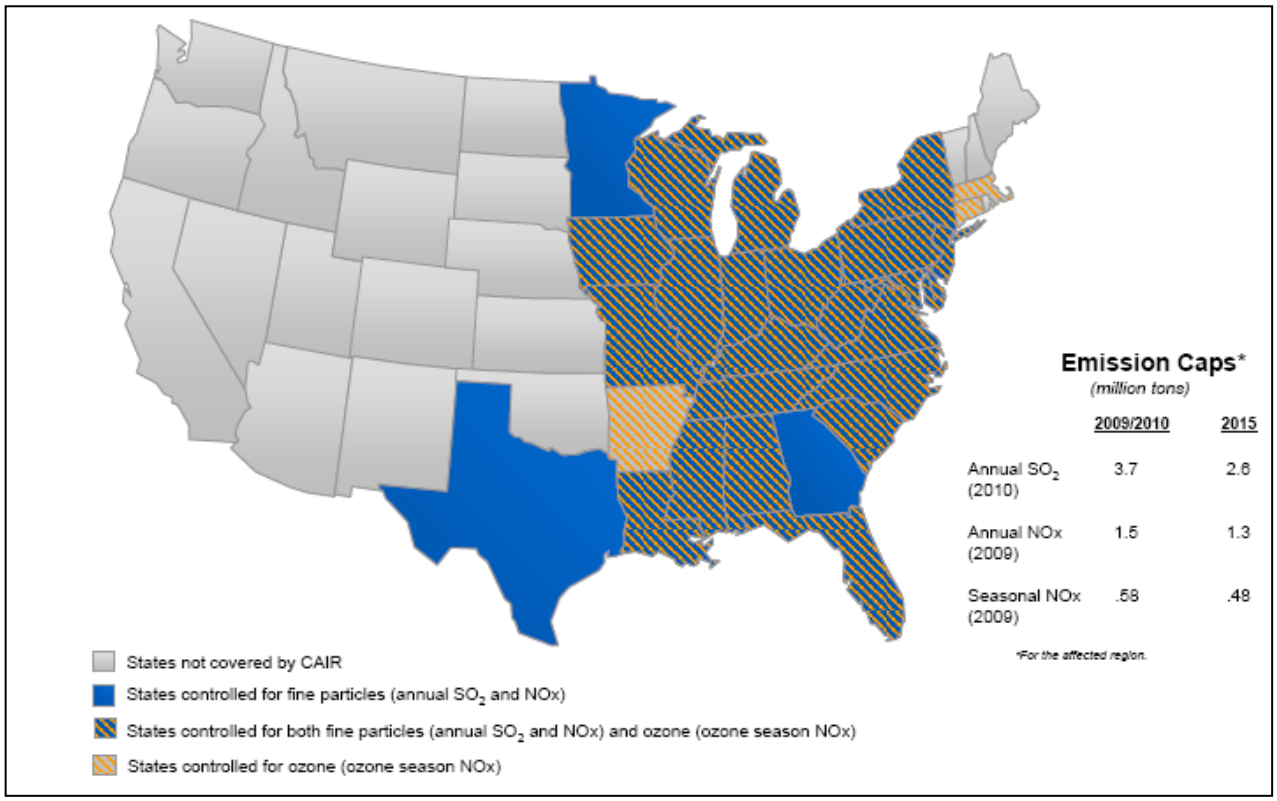

Figure 5. CAIR state coverage and emission caps. Adapted from the EPA Office of Air and Radiation: Clean Air Interstate Rule (2005).

In addition, all new coal-fired power plants and any plants that undergo major reconstruction or modifications will be subject to the following NSPS and NSR NO_x emission requirements shown in Table 1 below:

Table 1. New and modified coal-fired power plant NO_x emission limit. Adapted from Department of Energy (DOE) National Energy Technology Laboratory (NETL) (2000).

Unit built or modified on or after	Type of Source	Emission limit (lb/MMBtu)	Percentage Reduction of Potential Combustion Concentration
Aug. 17, 1971	Lignite	0.6	N/A
	Anthracite, bituminous, or subbituminous coals	0.7	N/A
	ND, SD or MT lignite and burned in cyclone boilers	0.8	N/A
Sept. 18, 1978	Lignite	0.6	65
	Anthracite or bituminous coals	0.6	65
	Subbituminous coals	0.5	65
	ND, SD or MT lignite and burned in slag tap furnaces	0.8	65
July 9, 1997	New Unit	1.0 lb/MWh (gross energy output basis)	N/A
	Reconstructed Unit	0.15	N/A
Feb. 28, 2005	New Unit	1.0 lb/MWh (gross energy output basis)	N/A
	Reconstructed Unit	0.11	N/A
	Modified Unit	0.15	N/A

NO_x FORMATION

In order to reduce or limit NO_x emissions, a good understanding of how NO_x reactions occur during the combustion process is required. "NO_x produced in a reactor depends on many factors, including: the type of fuel, the amount of oxygen available, and the temperature of the flame" (Goughnour, 2006). NO_x is formed from nitrogen found in the air, called thermal NO_x, from nitrogen in the fuel, called fuel NO_x, and from the oxidation of HCN, called prompt NO_x.

Thermal NO_x formation is modeled by the Zeldovich reactions. The amount of thermal NO_x produced is strongly linked to the time that combustion products spend at high temperatures (Turns, 1996). Thermal NO_x reactions have high activation energies and do not become significant until temperatures start to exceed the 1800 K range (Thien, 2002). "Thermal NO_x can typically represent up to 20% of the NO_x emitted during pulverized coal combustion in utility boilers" (Srivastava et al., 2005).

The prompt NO_x is formed at the flame front in the fuel-rich environment in which radical nitrogen molecules react to form HCN in the presence of CH. The HCN then reacts with radical oxygen molecules to produce either elemental nitrogen or NO_x. The prompt NO_x is modeled by the Fenimore equations (Turns, 1996). "Prompt NO_x contributes a relatively minor fraction of total NO_x emissions for coal-fired boilers" (Srivastava et al., 2005).

Coal contains nitrogen which is typically released as a mixture of HCN, NH_3, and N_2. The HCN and NH_3 can result in fuel NO_x production. The fuel NO_x for coal combustion typically forms 80% of the total NO_x formed in the entire combustion

process due to the higher amount of NO_x within the solid fuel (Pershing, 1976). The fuel NO_x that "may typically contribute up to 80% of the NO_x emissions. . . depends on the nitrogen content in the fuel and the amount of oxygen available to react with the nitrogen during coal devolatilization in the early stages of combustion" (Srivastava et al., 2005). Fuel NO_x can be reduced by cofiring coal with a fuel that has lower nitrogen content and/or by limiting the oxygen availability during the early stages of combustion as in a LNB furnace (Srivastava et al., 2005).

Thien (2002) describes the following general mechanisms of NO_x formation during combustion processes:

1. Thermal NO_x is primarily a function of high temperature usually greater than 1800 K and residence time of nitrogen at that temperature. It is modeled by the following Zeldovich reactions:

   $$O + N_2 \leftrightarrow NO + N$$

   $$N + O_2 \leftrightarrow NO + O$$

   $$N + OH \leftrightarrow NO + H$$

2. Prompt NO_x is the reaction of atmospheric nitrogen with fuel derived hydrocarbon fragments:

   $$CH + N_2 \leftrightarrow HCN + N$$

   $$C + N_2 \leftrightarrow CN + N$$

   HCN converts to N_2 or combines with O radicals to form NO:

   $$HCN + O \leftrightarrow NCO + H$$

   $$NCO + H \leftrightarrow NH + CO$$

$NH + H \leftrightarrow N + H_2$

$N + OH \leftrightarrow NO + H$

3. Fuel NO_x is oxidation of the fuel-bound nitrogen (Figure 6).

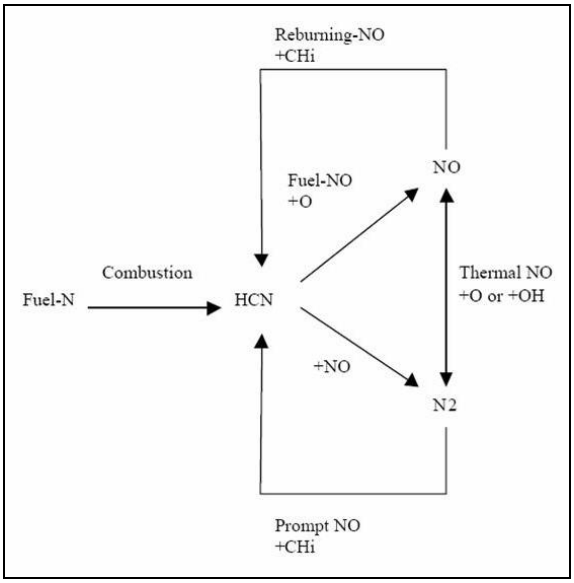

Figure 6. NO creation and destruction pathways. Adapted from Thien (2002).

DB POLLUTION

Manure is another waste product that without proper handling and disposal adversely impacts the environment. Thien (2002), Carlin (2005), and Lawrence (2007) have also conducted extensive analysis of the effects of manure pollution and the overall processing of dairy manure for cofiring in a coal-fired burner. Thien (2002) analyzed in great detail the overall Feedlot Biomass (FB) process to include animal feed composition, collection and storage of manure waste and their associated problems, the manure composting process, and FB fuel property dependence on the way that the

manure is harvested. Carlin (2005) details numerous techniques being used to currently dispose of DB and reports problems such as lagoon overflow and water source contamination due to the fact that "the nutrients in the manure (phosphates, nitrates, etc) can leach to groundwater when soil and plants do not fully absorb them, particularly in times of heavy rainfall." Lawrence (2007) reports that PM or dust from feedlot ranges in size from 8.5 to 12 microns and that the TSP found in feedlot dust can range from 150 $\mu g/m^3$ to 400 $\mu g/m^3$. This exceeds PM 10 regulation that requires concentration of particles less than 10 µm to be less than 150 $\mu g/m^3$.

Pennsylvania State University investigated installing a state-of-the-art circulating fluidized bed boiler in order to evaluate cofiring multiple biofuels and other wastes with coal (Miller et al., 2003). Pennsylvania State University analyzed over twenty different biomass, animal waste, and other wastes and found that cofiring a blend of biofuels with an appropriate nonfouling coal (that makes up the majority of the thermal input) would not pose any problems in the CFB system (Miller et al., 2003). This could also result in overall savings from NO_x and SO_2 credits due to potential decreased emissions from the use of these renewable fuels.

COFIRING DB

According to Mukhtar (2008), dairy biomass is an excellent feedstock for alternative energy systems due to its high heating value of 8,500 BTU/lb on a dry ash-free basis, which is comparable to as-received low grade coal, and would be an excellent mitigation measure to reduce excessive nutrient loading of land, groundwater and

waterways. Mukhtar (2008) states that the successful use of animal manure for fuel depends upon its meeting the required physical and chemical characteristics, such as (a) low moisture, (b) low ash, (c) homogenous in physical form and (d) low delivered cost, that are ideal for thermal conversion systems.

Baxter (2004) finds that cofiring biomass with coal simultaneously provides among the most effective means of reducing net CO_2 emissions from coal-based power plants and among the most efficient and inexpensive use of biomass. Baxter (2004) summarizes recent reviews of cofiring experiences that identify over 100 successful field demonstrations in 16 countries that use essentially every major type of biomass (herbaceous, woody, animal wastes and anthropomorphic wastes) combined with essentially every rank of coal and combusted in essentially every major type of boiler. He then goes on to include the International Energy Agency Bioenergy Task 32 group's draft position paper that indicates cofiring represents among the lowest risk, least expensive, most efficient, and shortest term options for renewable-based electrical power generation based in part on these recent discussions. Baxter (2004) found cofiring installation costs in many power plants would range from $50-$300/kW of biomass capacity which are achieved primarily because cofiring makes use of the existing infrastructure of a power plant with minimal changes; however, cofiring will be more expensive than equivalent fossil energy due to the fact that even "if the fuel is nominally free at the point of its generation (as many residues are), its transportation, preparation, and on-site handling typically increases its effective cost per unit energy such that it rivals and sometimes exceeds that of coal" (Baxter, 2004). Costello (1999) concludes

that to be economical, it is estimated that biomass fuel must be delivered at a price $0.25 to $.40/MMBtu below the price of coal, which decreases the biomass transportation distance due to the unnecessary fuel cost added (Costello, 1999). Baxter (2004) also states that biomass fuels commonly contain more moisture than coal which decreases peak combustion temperatures and thus NO_x emissions. Even with some of these advantages, there are major technical challenges associated with biomass cofiring which include:

1. Fuel preparation including grinding, storage, and delivery,
2. Ash deposition,
3. Fuel conversion,
4. Pollutant formation,
5. Corrosion,
6. Fly ash utilization,
7. Impacts on SCR systems, and
8. Formation of striated flows.

Partlow et al. (2003a) finds that current low NO_x designs require fineness above 70 percent passing through a 200 mesh screen. Based on this industry requirement and other DB properties required for cofiring in a coal-fired power plant, it is important to focus on the harvesting and composting methods used to prepare, store and transport the manure. Lawrence (2007) has provided a description of how the LA-PC-DB-SepS fuel is collected from flushed manure from the milking house of a dairy and passed through a

mechanical separator to remove most fine solids including ash prior to air drying and grinding.

Thien (2002) found that "Coal:biomass blends fired in boiler burners, produce lower or similar levels of NO (0.15kg/GJ) compared to coal even though FB has a higher N, due to biomass N release in the form of NH_3 and biomass's high volatile content." Annamalai et al. (2003) used cattle feedlot biomass for cofiring and found that it reduced NO_x emissions by about 10% but increased CO emissions. While Thien (2002) and Annamalai et al. (2003) used FB with 70% passing through a 200 mesh screen, Lawrence (2007) cofired coal with DB where 70% passed through a 200 mesh screen and reports the following conclusions:

1. Due to "the uncertainty in CO measurements being a percentage of the reading . . . [t]he uncertainty bands overlap too much to draw any conclusions about the effect of blending coal with DB on CO production."
2. In the lean region, the blended fuels produce more NO_x than the pure coal with the 90:10 WYO:DB fuel blend producing over 600 ppm (corrected to 3% O_2) of NO_x as compared to the pure WYO production of approximately 450 ppm (corrected to 3% O_2) of NO_x. In the slightly rich region, the blended fuels produced less NO_x than the pure coal.

It is apparent the particle size of DB used by Lawrence (2007) is much higher when compared to the size used by previous researchers.

NO_x CONTROL TECHNOLOGIES

Two current approaches being used in coal-fired boilers to control NO_x emissions are exhaust gas treatment and combustion modification (Goughnour, 2006).

Exhaust gas treatment also described as post combustion treatment includes SCR and SNCR. SCR typically involves the injection of ammonia and its reaction with NO_x on the surface of a catalyst; however, the catalyst life is uncertain and these SCR retrofits are often complex with fan upgrades and major duct modifications resulting in high capital costs. "Apart from requiring very expensive materials, catalysts are prone to fouling by particulate matter and poisoning by various chemical species present in flue gas depending upon the type and source of the fuel. These can essentially reduce catalyst life" (Basu, 2007). Basu (2007) has also provided a comprehensive review of the recently developed chemical and biochemical processes for NO_x control. SNCR technologies include injecting NH_3 into the exhaust stream which reacts with NO_x to form H_2O and N_2 and the injection of NH_2CONH_2 or $(HOCN)_3$ into the exhaust stream which decomposes and reacts with NO in the same manner as the ammonia (Goughnour, 2006).

Combustion modification includes the LNB design which decreases NO_x emissions by utilizing fuel and air staging inside the burner. Other modifications include overfire air (OFA) or the addition of air into the upper level of the combustor, reburning which involves injecting additional fuel above the existing burner zone, and advanced reburning (AR) which is a combination of reburning and SNCR. LNBs are typically considered the best cost effective technique (Zamansky et al., 2003). Srivastava et al.

(2005) finds that the LNB has an average NO_x reduction efficiency of 39.2% for bituminous coals and can achieve greater efficiencies when combined with other modifications such as OFA (Figure 7).

Boiler Type[a]	Coal Type	Primary Control Technology	1995 Average Baseline NO_x Emission (lb/10^6 Btu)	2003 Average Controlled NO_x Emission (lb/10^6 Btu)	Average NO_x Reduction Efficiency (%)	Range of NO_x Reduction Efficiencies (%)	No. of Boilers
Wall-fired	Bituminous	LNB	0.71	0.41	39.2	8.6–70.1	62
Wall-fired	Bituminous	LNBO	0.81	0.35	53.3	32.7–71.9	16
Wall-fired	Subbituminous	LNB	0.59	0.28	45.5	19.4–80.3	16
Wall-fired	Subbituminous	LNBO	0.41	0.14	63.4	40.0–80.9	4
Tangential-fired	Bituminous	LNC1	0.62	0.39	35.0	17.2–65.4	26
Tangential-fired	Bituminous	LNC2	0.48	0.31	36.6	23.3–70.8	15
Tangential-fired	Bituminous	LNC3	0.56	0.25	54.9	38.1–72.2	19
Tangential-fired	Subbituminous	LNC1	0.38	0.21	45.4	11.3–74.4	18
Tangential-fired	Subbituminous	LNC2	0.43	0.23	45.6	33.9–65.4	3
Tangential-fired	Subbituminous	LNC3	0.35	0.14	60.5	48.2–77.2	23

Notes: LNB = low-NO_x burner; LNBO = LNB with OFA; LNC1 = LNB with close-coupled OFA; LNC2 = LNB with separated OFA; and LNC3 = LNB with both close-coupled and separated OFA. [a]All boilers are dry-bottom type.

Figure 7. NO_x reduction performance of primary control technology applications on coal-fired boilers. Adapted from Srivastava et al. (2005).

LOW NO_x BURNER

The design of LNBs is being utilized in the construction of new coal fired power plants as well as the retrofit and modification of existing power plants in order to meet today's stringent emission standards. Steitz et al. (1998) describes the low NO_x concept which focuses on dividing the secondary air flow into two distinct paths to produce air separation from the coal, or air staging, within the near burner throat area in order to control fuel bound nitrogen from mixing early with secondary air. This delay inhibits the conversion of fuel nitrogen to NO_x. "In addition, this controlled mixing reduces

peak flame temperatures, limiting the formation of 'thermal NO_x' within the flame" (Steitz et al., 1998). "In the aerodynamically staged LNB, mixing with the fuel of a portion of the combustion air required for complete combustion of the fuel is delayed to produce a flame with a relatively large fuel-rich flame area within the flame" (Kobayashi et al., 2004) as shown in Figure 8.

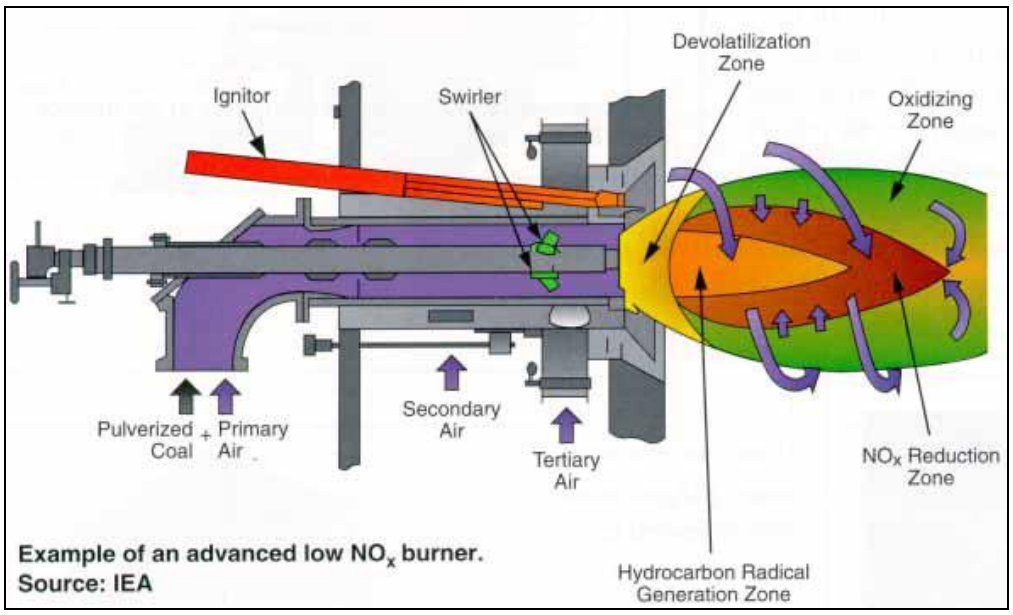

Figure 8. Low NO_x Burner example.
Adapted from Department of Energy (DOE) (1996).

In order to decrease NO_x production, the amount of air available to react with the fuel at the beginning of the combustion process is limited which helps to maintain a lower peak operating temperature. This has been defined as staging or delaying the total theoretical air from mixing with the fuel. A fuel-rich condition is established at the initial stage or primary zone of the combustion process with primary air and secondary

air allowing for combustion to occur. The introduction of secondary or tertiary air demonstrates the well-known usage of incomplete combustion to retard the production of NO_x from the burner (Pisano et al., 2007). This retardation is due to the overabundance of carbon dioxide, water vapor and methane in the burner mix at the initial stage. Narato et al. (1997) states that when the pulverized coal combustion burner is made up of a pulverized coal nozzle for injecting a coal/primary air mixture as well as secondary and tertiary air nozzles arranged concentrically, a reducing flame region and an oxidizing flame region can be formed in the flame that will help keep production of NO_x to a low level. The reaction rates for reactions such as CO and CO_2 are much faster than the reaction rate of NO_x due to the fact that "NO_x kinetics are slow and, hence, NO is formed in ppm; thus, it can be treated as a trace species" (Annamalai et al., 2007).

In a LNB, the air is also staged in order to ensure that there is insufficient oxygen available to react with radical nitrogen molecules in the primary combustion zone resulting in an increase in the production of elemental or "molecular nitrogen" (Rabovitser et al., 2001). "[A]ir staging divides the combustion process into a primary zone with a deficiency of air and a second reburn zone run with excess air" (Magel, 1996). "The formation of NO_x from fuel nitrogen is based on a competition between the formation of NO_x and the formation of N_2 from the nitrogenous species in the fuel volatiles and char nitrogen" where the staged combustion carefully controls the mixing of air and fuel to create the fuel-rich condition which "drives the reactions to form N_2" (Kobayashi et al., 2007). The limited oxygen available in the fuel-rich primary combustion zone forces any radical nitrogen molecules to form N_2. The N_2 does not

react with any of the remaining oxygen provided by the tertiary air in the secondary combustion zone. This results in more N_2 being produced while reducing the overall amount of NO_x produced. Some of the modern LNBs have operated the burners near stoichiometry to slightly rich; these burners have utilized overfire air (OFA) downstream to provide excess air in order to complete the combustion process which is known as globally staged combustion (Kobayashi et al., 2004) as shown in Figure 9.

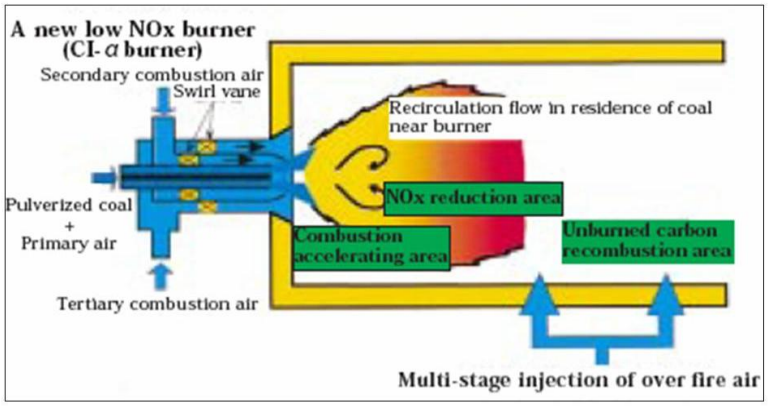

Figure 9. NO_x reduction area in low NO_x burner. Adapted from Hisao (1996).

Izuha et al. (1983) states that the primary air, secondary air and tertiary air are distinct from one another in amount and that the total is equal to the amount of air necessary for burning the pulverized coal in complete combustion. Kobayashi et al. (2004) finds that the "fuel rich flame zone stoichiometric ratio is between 0.6 and 1.0 and more preferably between 0.7 and 0.85." "Primary air to the pulverized coal combustor is preferably in the range of about 20% to about 30% by volume of the total combustion air required for complete combustion, secondary combustion air is

preferably in the range of about 35% to about 45% by volume of the total combustion air, and tertiary or overfire air is preferably in the range of about 30% to about 40% by volume of the total combustion air" (Rabovitser et al., 2001). Constraining the primary air input to approximately 20% of the theoretical or stoichiometric air required and the secondary air input to approximately 55% to 60% of the total stoichiometric air required creates a fuel-rich condition in the primary burn zone. The remainder of the oxygen required to complete the fuel combustion as well as any excess air is provided as tertiary air in the secondary burn zone as shown in Figure 10.

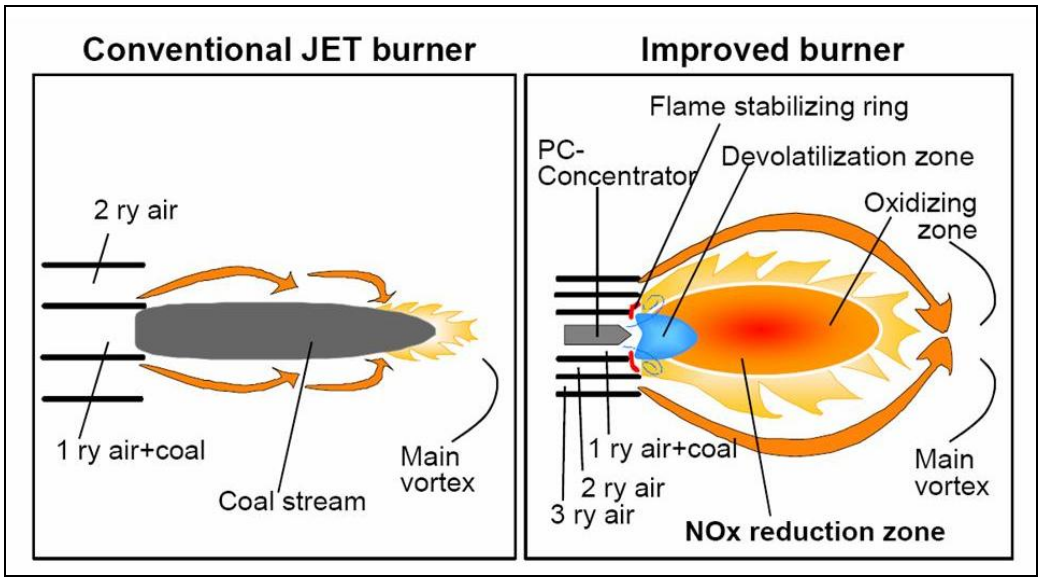

Figure 10. Comparison of conventional JET-burner with improved burner. Adapted from Yano et al. (2003).

PRIMARY AIR TO PULVERIZED COAL (PA/PC) RATIO

LaRue et al. (1997) states that at the primary air and pulverized coal nozzle exit location, the relative amount of pulverized air to pulverized coal sets the stoichiometry in the fuel rich core of the burner which is a critical parameter that affects ignition and the rate of combustion. The quantity of volatile matter and its release rate, which are critical to the formation and control of NO_x emissions, are dependent on inherent coal properties and also on the amount of coal particle heating. LaRue et al. (1997) finds that NO_x is most readily controlled by fuel nitrogen which is released with the volatiles, in a fuel rich environment. When the PA/PC ratio is too low, insufficient air is available to burn much of the volatile matter which reduces temperature in the flame core. Since the quantity of volatile matter released by a coal particle is a function of the temperature the particle reaches, the lower temperatures result in lower volatile matter production. Therefore, a PA/PC ratio that is too low retards the rate of combustion in the flame core, pushing combustion downstream in the flame where the flame core diffuses into a more air-rich environment, causing an increase in NO_x formation. According to LaRue et al. (1997), a PA/PC ratio that is too high permits NH_i (where i=1,2,3) and CN species (released from volatile matter) to oxidize to NO and an excessively high PA/PC ratio also has a moderating effect on temperature and flame stabilization. LaRue et al. (1997) finds that "PA/PC ratios typically vary from about 1.0 to 2.0 lb air/lb of coal for different types of pulverizers at their maximum design grinding capacity" and defines the "[O]ptimum core air flow rate (lb/hr) = 1.2xcoal flow rate (lb/hr)x(%VM/100)." LaRue et al. (1997) reports that "[t]est results have also shown that low NO_x emissions can also

be achieved when operating with an amount of core air flow within approximately plus/minus 25% of the optimum core air flow rate defined above."

From October 1998 through September 2001, a prototype ultra low-NO_x burner, which is a plug-in version of the Babcock & Wilcox's DRB-4Z^{TM} ultra low-NO_x PC burner, was fabricated and tested at the 100 MMBtu/hr Babcock & Wilcox Clean Environment Development Facility. Based on these tests, Warchol et al. (2001) found that within certain limits, raising the primary airflow rate or the primary combustion zone stoichiometry increases the flame temperature and enhances the early release of NO_x precursors which also helps to preserve the pulverized coal jet from rapid dispersion and mixing with the swirling secondary air streams.

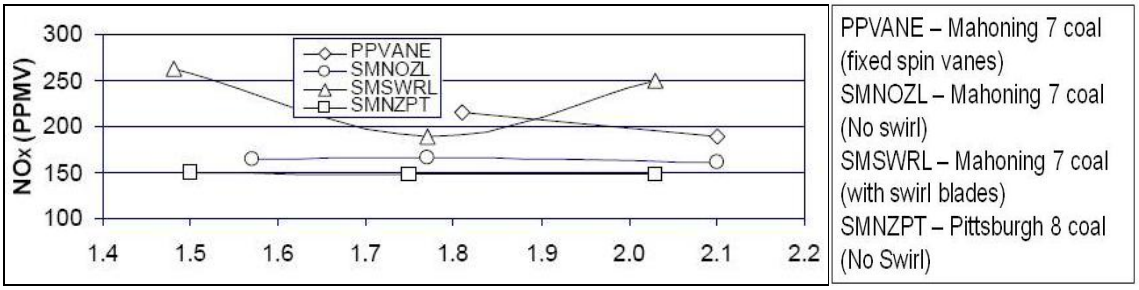

Figure 11. Effects of increasing PA/PC ratio on NO_x emissions. Adapted from Warchol et al. (2001).

Based on results shown in Figure 11 for testing completed for the four configurations of the ultra low-NO_x plug-in DRB-4Z^{TM} PC burner firing pulverized coal at 100 MMBtu/hr and 17% excess air, one configuration (without swirl) showed reduced NO_x productions as PA/PC ratio increased above 1.8, two configurations (also without swirl) showed no change in NO_x concentrations, and the fourth configuration "with a

multi-bladed swirler positioned inside the reduced diameter coal nozzle (SMSWRL case), the axial momentum of the PC transport jet was no longer preserved and after an initial drop in NO_x emissions, further increase in PA/PC resulted in higher NO_x generation" (Warchol et al., 2001).

SWIRL EFFECTS

The swirl number is defined as the ratio of tangential to axial momentum and is mathematically defined as the following for an axial swirler (Figure 12):

$$S := \frac{2}{3} \cdot \left[\frac{1 - \left(\frac{r_h}{r_b} \right)^3}{1 - \left(\frac{r_h}{r_b} \right)} \right] \cdot \tan(\alpha)$$

Figure 12. Swirl number calculation. Adapted from Sami (2000).

where,

r_h = hub radius (inner diameter)

r_b = tube radius (outer diameter)

α = blade angle (degrees)

Thien (2002) discussed the conventional combustion boiler set up where the fuel, usually pulverized coal, is blown by a carrier or primary air while the remainder of the air is given a swirl motion by swirl vanes in order to create the RZ. This recirculation zone

makes the flame more stable by continuously reigniting the coal as it comes into the burner. In LNB, typically swirl generators are used in secondary and tertiary air streams to impart swirling flows which create a recirculation zone for better flame stability (Kobayashi et al., 2007).

According to Cole (1998), both radial and axial swirl registers can produce the air flow patterns necessary for achieving stable flame combustion, turndown, and emissions with the LNB achieving NO_x reductions greater than 50% on both types firing a wide range of coals. A key requirement of any LNB register is to produce a strong swirling air flow pattern exiting the burner throats, coupled with a well defined internal recirculation zone. The recirculation pattern within this swirling vortex reduces the velocity and penetration of the coal jet which aids in establishing a flame front near the coal nozzle tip. The coal, which ignites and devolatizes under fuel-rich conditions in this inert recirculation zone, prevents the complete conversion of fuel bound nitrogen to NO_x, and the surrounding swirling air shears the coal jet around its circumference, while radially stratifying the flow with its angular momentum so that later on in the combustion process, the swirl allows a gradual entrainment of fuel and air to complete carbon burnout. "The capability to adjust air flow provides flame shaping as well as fuel and air mixing control, reducing emissions and maximizing combustion efficiency" (Cole, 1998). Azuhata et al. (1990) finds that the swirl flow generator associated with the tertiary air passage can delay the mixing of the tertiary air with the straight flow of the fuel by changing the tertiary air to a swirl flow. The tertiary swirl flow can promote, at a downstream portion of the flame, the mixing of tertiary air with the combustibles

retained in the reduction region by the use of a low pressure area originated in the swirl flow which prevents the flame from being lengthened and the combustion efficiency from being worsened. The following figure illustrates the swirl effects on the IRZ:

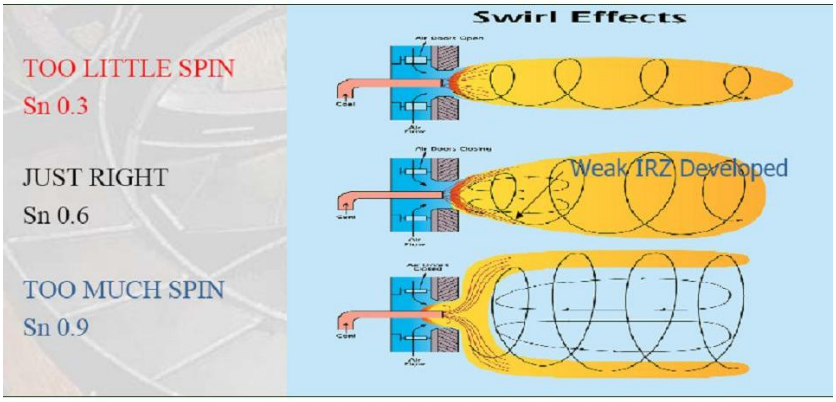

Figure 13. Swirl Effects on Internal Recirculation Zone (IRZ). Adapted from Jin et al. (2005).

Sami (2000) observed the following two competing trends regarding the swirl number: when the swirl number increases, a reduction in air entrainment takes place causing less NO. On the other hand, an increase in the swirl number will cause more mixing of fuel volatiles and oxidizer causing more NO. From a swirl number of 0 to 0.6, the first effect dominates causing the NO to drop; however, for swirl numbers greater than 0.6, mixing dominates and NO increases regardless of the fact that air entrainment is reduced as shown in Figure 13.

Previous experiments were conducted to determine whether the number of burners used in a boiler would have any effect on NO_x emissions set at the same swirl number. A single 5 MMBtu/hr burner and a multiple burner boiler consisting of three

1.5 MMBtu/hr burners were evaluated at various swirl settings with 100% being set at a maximum swirl of 2 (Eddings et al., 2000). At swirl numbers between 25% and 100% the greatest NO_x reduction occurs with the single burner producing less NO_x than the multiple burners at the same swirl number (Figure 14).

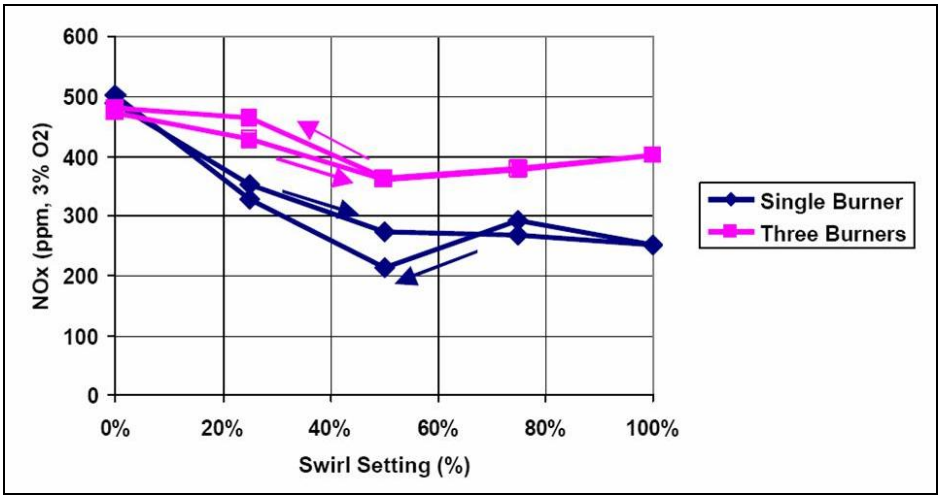

Figure 14. Swirl effect on single and multiple burners. Adapted from Eddings et al. (2000).

CURRENT APPLICATIONS OF LNB TECHNOLOGY

Beginning in May 1993, the Georgia Power Company (GPC) provided Hammond Unit 4, a 500 MW boiler, for testing of a low NO_x retrofit with AOFA funded by DOE, the Southern Company, and EPRI. At the top load, the LNB plus AOFA retrofit resulted in approximately 67 percent reduction in NO_x from the Baseline configuration with effectiveness generally between 57 and 67 percent over the useful load range (Smith et al., 1995).

In 1999, CP/UPA converted their 550 MW, lignite-fired Coal Creek Unit #2 to a low NO_x burner using FWEC Tangential Low NO_x (TLN) system. It is common for lignite-fired units to have between 40 and 60 percent of the total combustion air admitted into the furnace as primary air from the pulverizer system due to the required air for drying and conveying of the low Btu fuel while bituminous fuel-fired units operate with only 15 to 25 percent primary air flow (Heinz et al., 1999). Following installation of the TLN system, NO_x emissions were reduced from 0.57 lb/MMBtu annual average level to below the 0.35 lb/MMBtu annual average guarantee level with a 50% low load NOx reduction (Heinz et al., 1999). The annual average NO_x emissions were reduced by over 39% with the TLN system.

Reliant Energy's W.A. Parish Generating Plant installed the first commercial DRB-4Z^{TM} low NO_x burners with an interlaced overfire air system on Unit 6, which was a 690 MW natural circulating, opposed-wall coal-fired boiler consisting of 56 B&W dual register burners in operation since 1978 and burns a PRB sub-bituminous coal. "NO_x was reduced to 0.17 lb/Mbtu or below, which represents a 51% reduction from pre-retrofit levels" (Bryk et al., 2000) as shown in Figures 15 and 16.

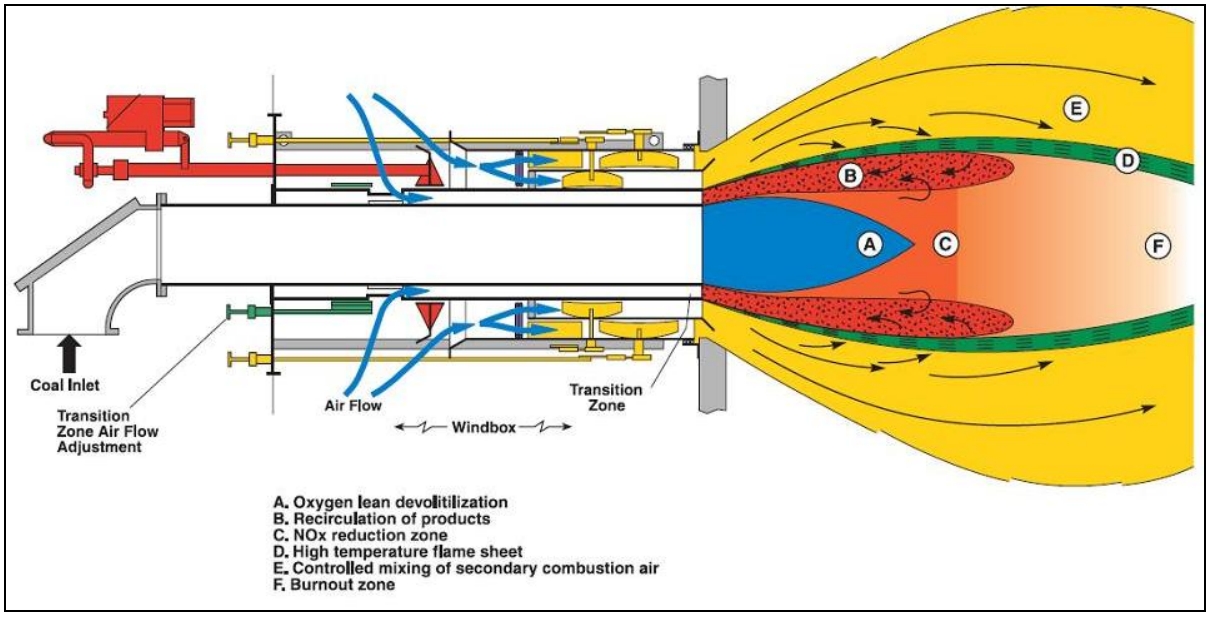

Figure 15. Ultra-low NO_x coal-fired burner. Adapted from Bryk et al. (2000).

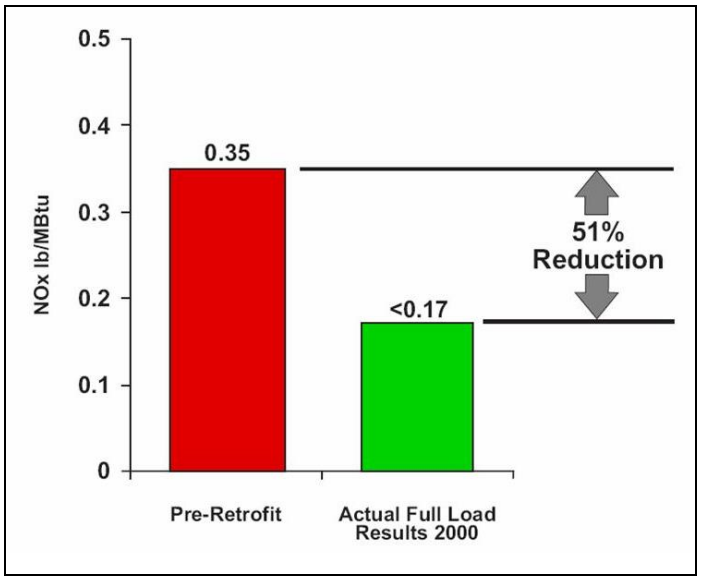

Figure 16. NO_x reduction results. Adapted from Bryk et al. (2000).

Rensselear Polytechnic Institute retrofitted three 115 MW utility boilers with low NO_x burners. The boilers fired eastern bituminous coal reducing NO_x emissions on these

units approximately 64% from 1.0 to 0.36 lb/mmBtu using burners only and no OFA was used (Penterson et al., 2003).

In May 2000, the Texas Municipal Power Agency (TMPA) identified combustion based NO_x control options for their 480 MW tangential coal-fired Gibbons Creek unit which included a Foster Wheeler tangential low NO_x burner system. "Initial post-retrofit results show that average NO_x emissions at Gibbons Creek were reduced from approximately 0.32 lb/MBtu to below 0.11 lb/MBtu while maintaining less than 5 ppm CO" (Partlow et al., 2003b). The modifications to the Gibbons Creek unit resulted in more than a 66% reduction in NO_x emissions with some levels as low as 0.085 lb/MBtu as shown in Figure 17.

MCR Emission Comparison

	Pre-retrofit	Post-retrofit (w/FI)
NO_x	0.30 to 0.37 lb/MBTu	0.085 to 0.110 lb/MBTu
CO	0 to 900 ppm	less than 5 ppm
LOI	0.3%	0.1%
Opacity	less than 5%	less than 5%

Figure 17. Performance of Gibbons Creek unit before and after retrofit with the Foster Wheeler TLN3 burner. Adapted from Partlow et al. (2003b).

In 2000, Reliant Energy retrofitted the 820 MW Limestone Electric Generating Station #2 with Foster Wheeler Energy Corporation's Tangential Low NO_x system with the goal of reducing NO_x levels from a baseline of 0.42 lb/MMBtu (Pearce et al., 2000). Given the constraint that carbon monoxide levels not exceed 60 ppm (corr.3%O_2) over

any 8 hour period regardless of fuel, controlling CO levels to such low levels, under ultra low NO_x air staging conditions and load cycling operation, is one of the challenges facing low NO_x burner designers. CO is not easily predicted like NO_x, unburned carbon or boiler performance due to the fact that CO formation is related primarily to the degree of fuel and air mixing. FWEC TLN design requirements stress fuel / air balance and mixing for successful ultra low tangential coal firing where industry experience verifies that improper air or fuel distribution, jet penetration and mixing can result in very high CO levels, particularly with reactive coals like lignite and PRB (Pearce et al., 2000). Pearce et al. (2000) reports that "[a]verage NO_x emissions were reduced by 55% from pre-retrofit levels to approximately 0.19 lb/MMBtu at full load over the range of lignite, while maintaining an average CO level of 15 ppm over each 8 hour period."

Hitachi group in Japan has focused their research and development on low NO_x combustion technologies for pulverized coal designing the first generation HT-NR based on the theory of "In-Flame NO_x reduction," the second generation HT-NR2 focused on higher efficiency and easier maintenance, and the third generation HT-NR3 based on the concept of a wider and shorter flame for extremely low NO_x combustion. The concept of a wider and shorter flame is based on expanding the recirculation region around the flame stabilizing ring and optimizing the implementation of outer air where it is "important to separate tertiary air from the high-temperature reducing zone formed near the burner throat" to achieve low-NO_x combustion (Yano et al., 2003); therefore, the more the outer air is separated, the greater the increase in the reduction zone as shown in Figure 18.

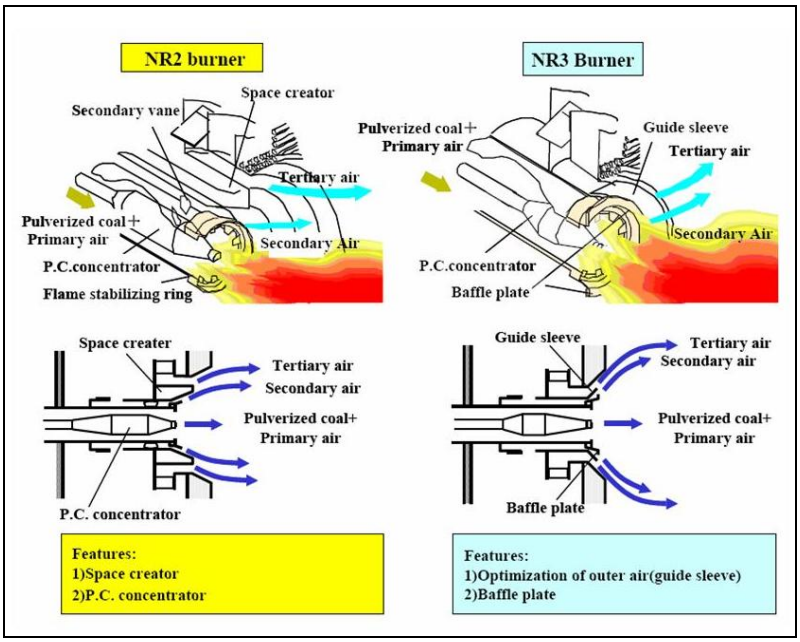

Figure 18. Hitachi HT-NR2 and HT-NR3 low NO_x combustion technologies. Adapted from Yano et al. (2003).

The performance of these low NO_x technologies were verified at the IN thermal power plant in Finland where modification and commissioning was carried out in the summer of 1997. Based on the plant modifications, the two-stage retrofit reduced NO_x emissions by more than 40% while the third generation retrofit reduced NO_x emissions by as much as 75% when compare to the conventional boiler prior to retrofit (Figure 19).

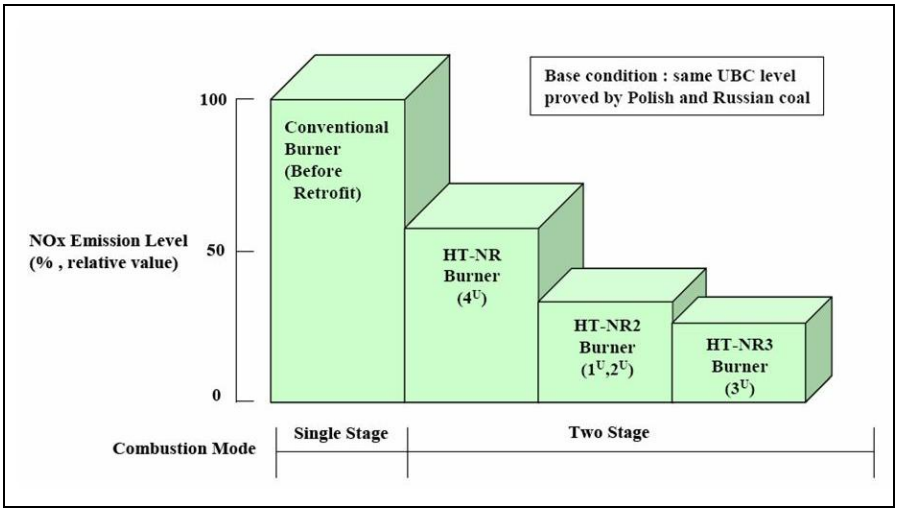

Figure 19. Result of Combustion Performance Tests after Retrofits of thermal power plant IN in Finland consisting of four 265 MW pulverized coal-fired boilers. Adapted from Yano et al. (2003).

CHAPTER III

OBJECTIVES AND TASKS

The overall objective of the proposed research is to develop a small scale (100,000 BTU/hr) low-NO_x burner to reduce overall NO_x emissions when using blends of coal and animal waste based biomass fuels.

In order to achieve this objective, the following tasks are performed:

1. Obtain proximate and ultimate analysis of the WYO and LA-PC-DB-SepS.
2. Complete construction of the LNB nozzle design and burner system.
3. Conduct gas mixing tests on the LNB furnace to confirm the delay or staging of the tertiary air.
4. Perform parametric studies of coal and biomass fuel blends using the LNB at various equivalence ratios and analyzing the measurement readings of sampling gas in order to determine the effects of biomass fuel blends on NO_x emissions using a LNB furnace for the following cases:
    a. Effect of unstaged cofiring of WYO and WYO:DB fuel blends with a constant fuel feed rate / heat output of 100,000 BTU/hr.
    b. Effect of staged cofiring of WYO and WYO:DB fuel blends with a constant fuel feed rate / heat output of 100,000 BTU/hr.
    c. Effect of unstaged cofiring of WYO and WYO:DB fuel blends with a constant air flow maintain at stoichiometric air flow.

d. Effect of staged cofiring of WYO and WYO:DB fuel blends with a constant air flow maintain at stoichiometric air flow.

CHAPTER IV

EXPERIMENTAL SETUP AND PROCEDURES

The following is a detailed description of the experimental facility, instrumentation, experimental procedures, and uncertainty analysis conducted for this research.

EXPERIMENTAL FACILITY

The small scale (100,000 BTU/hr) LNB furnace was built at CBEL in TAMU. Some previous graduate students completed the design and the initial construction work of the furnace which was designed to burn solid fuels. The remainder of the construction has been completed during the current research. Figure 20 shows the conventional burner design while figure 21 shows the overall furnace set-up which was modified to include tertiary air flow in the LNB furnace design:

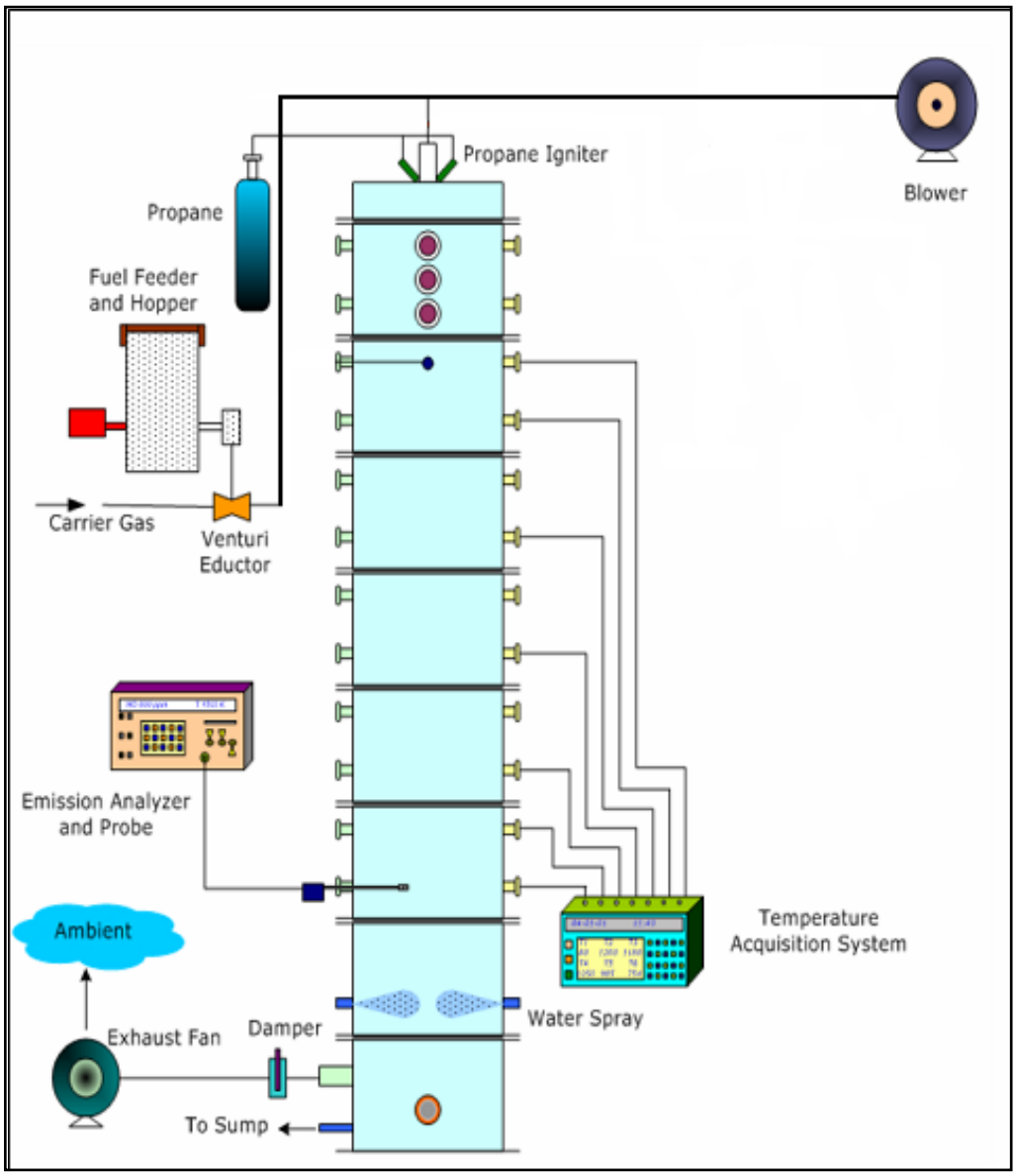

Figure 20. 100,000 BTU/hr Conventional Coal-fired burner diagram. Adapted from Thien (2002).

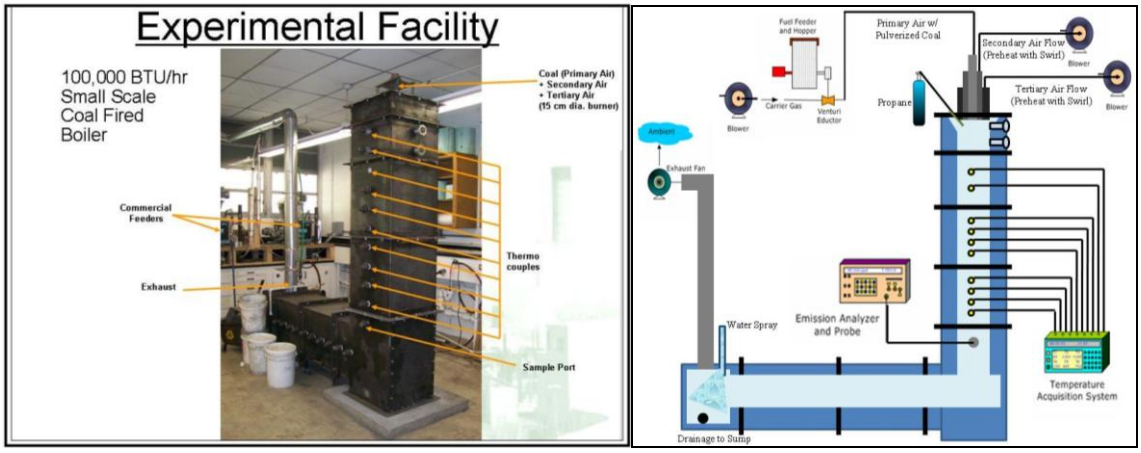

Figure 21. 100,000 BTU/hr Coal-fired burner located in the Coal and Biomass Laboratory at Texas A&M University.

One of the primary objectives during this research was to complete the design and construction of a LNB nozzle that could provide primary, secondary and tertiary air for staged combustion. After conducting literature review on various existing patents and commercial LNB nozzle designs, the following design was implemented and constructed for the current LNB furnace as shown in figure 22, figure 23, and figure 24:

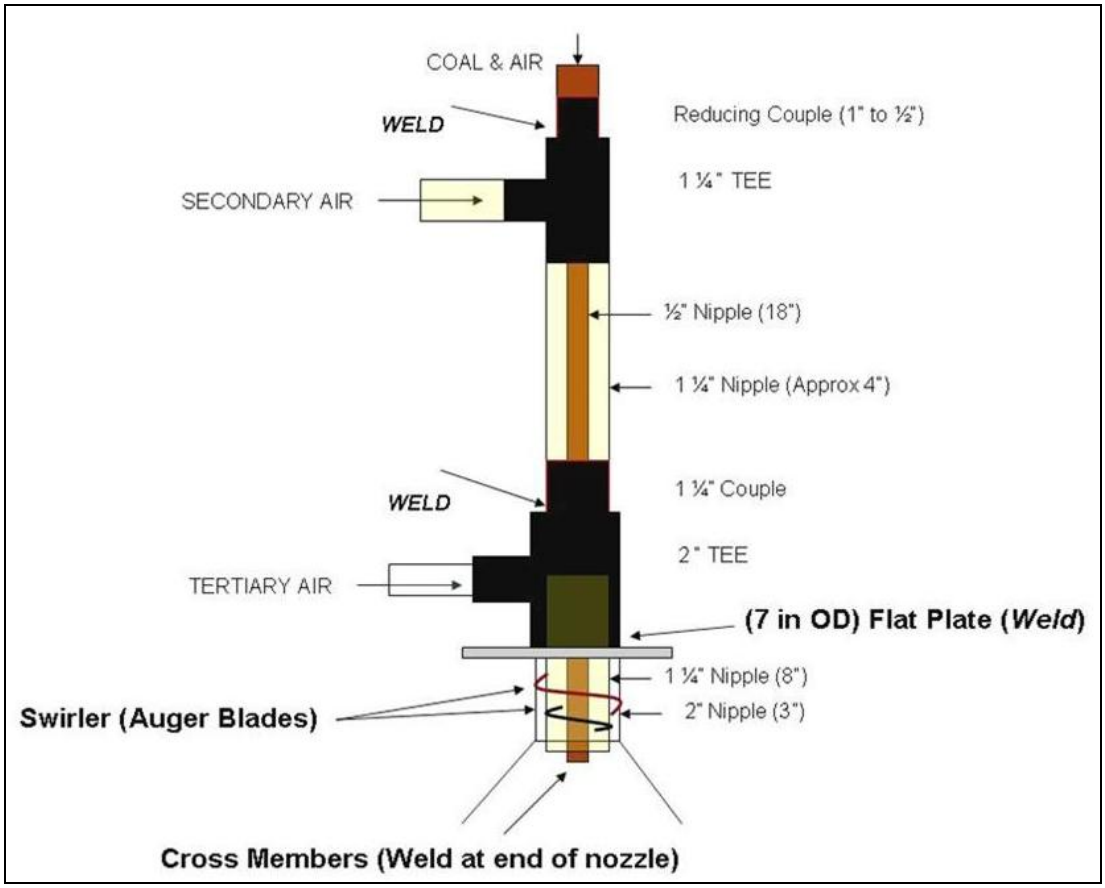

Figure 22. Low-NO_x burner design with primary, swirled secondary, and swirled tertiary air flow.

Figure 23. Completed construction of the Low-NO_x burner nozzle.

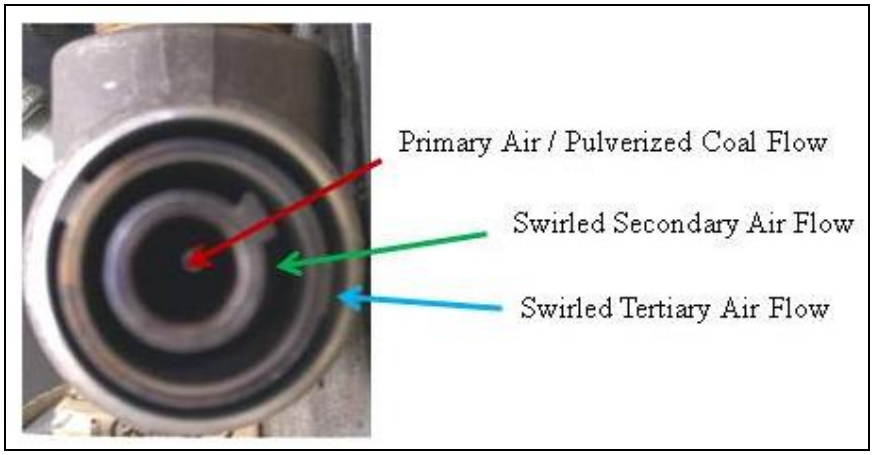

Figure 24. Nozzle view of outlets for primary, secondary and tertiary air flows.

One design criteria that has a significant effect on the LNB performance and ability to reduce NO_x is the swirl provided to the secondary and tertiary air flows that allows for mixing with the pulverized fuel particles as shown in figure 25 below. Based on the competing trends Sami (2000) identified, the secondary and tertiary air flows were designed to have a swirl number less than 0.6 to have the greatest NO_x reduction capability. The secondary air has a swirl number of 0.54 based on an inner diameter of 0.5 inches, an outer diameter of 1.13 inches and a blade angle of 45 degrees. The tertiary air has a swirl of 0.53 based on an inner diameter of 1.25 inches, an outer diameter of 2.88 inches and a blade angle of 45 degrees. The swirl was set at these values for all experiments conducted during this research; however, the swirl can be changed in future experiments to enhance swirl flow effects or to adjust the swirl angle in order to change the swirl number of the furnace. The swirl vanes are welded to the outside of the exit pipes for the primary and secondary air. These pipes are connected into unions and can be unscrewed for future modification of the swirl number.

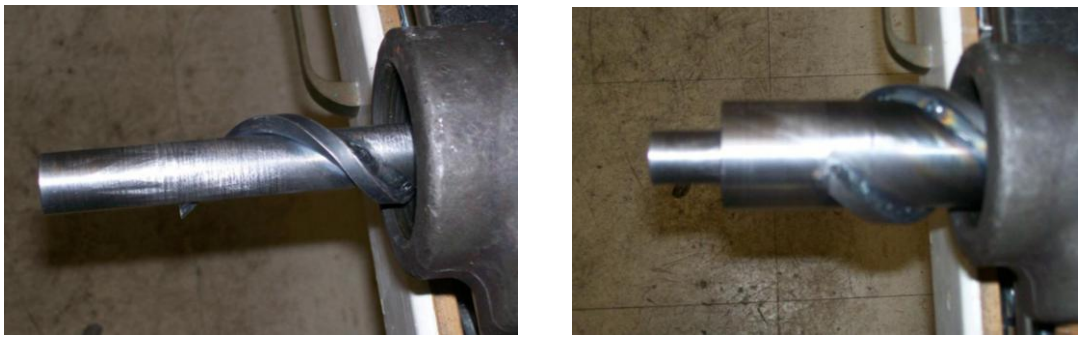

Figure 25. Swirl vanes welded on the secondary and tertiary air chambers.

Inside the furnace, the Quarl was designed and constructed by Thien (2002). The quarl is a diffuser that stabilizes the flow as it exits the burner nozzle and creates an area of lower pressure at the top of the furnace which helps to strengthen the recirculation zone. The quarl half angle for this furnace is 24^{o}" (Thien, 2002).

The furnace is made of multiple sections. Figure 26 shows a detailed view of the section of the furnace:

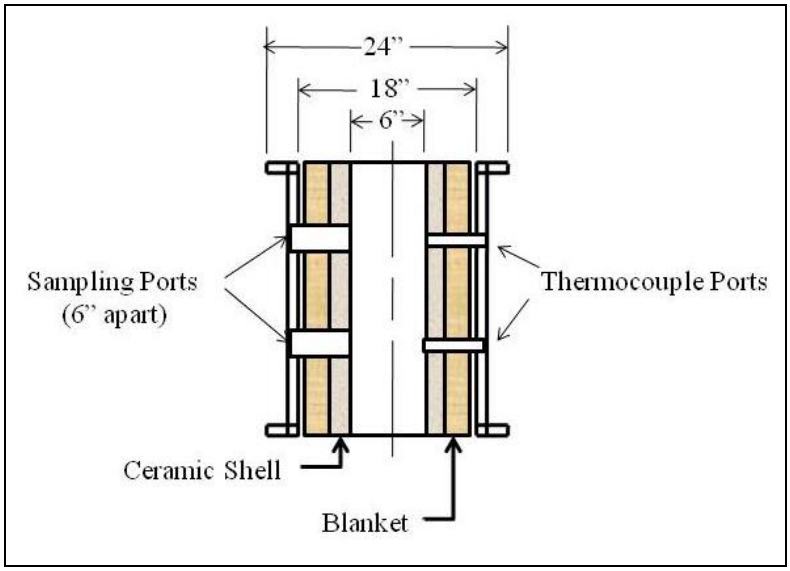

Figure 26. Refractory dimensions.

Thien (2002) provides a detailed description of the composition of the AP Greencast 94 castable ceramic used as the inner insulation layer and "cast into cylinders 0.1524 m (6 in) inner diameter, 0.254 m (10 in) outer diameter, and ~.03 m (~12 in) long" with a ceramic fiber blanket used as the second layer of insulation used in the LNB furnace construction.

The transport lines for the primary and tertiary air were constructed with half-inch diameter PVC pipes connected into galvanized steel pipes while the secondary air, which comprises the largest percentage of total supplied air, was constructed of one inch PVC pipe connecting into three-quarter inch galvanized steel pipes as shown in figure 27 below. Both the secondary and tertiary steel pipes were heated and insulated up to the top of the furnace nozzle.

Figure 27. Insulation installed on secondary and tertiary air pipes.

INSTRUMENTATION

The following is a detailed overview of the instrumentation used to conduct experiments for this research.

1. A Dwyer mass flow controller shown in figure 28 regulated each individual gas flow line and was connected to the LabVIEW program where the flow capacity can be individually controlled and monitored.

Figure 28. Dwyer mass flow controller series GFC.

The following table 2 illustrates the gas flow capacities and LabVIEW program set-up for this experimentation:

Table 2. LabVIEW programming parameters for gas flow meters.

Gas	Gas Flow Capacity SLPM (m^3/hr)	K Factor (to N_2) - multiplied to Capacity	5 Volt input (to Gas Flow Meter) - divide into Capacity	5000 Amp reading (From Gas Flow Meter) - multiply to Voltage reading
Nitrogen	100 (6)	1	20	50
Tertiary Air	200 (12)	1	40	25
Primary Air	200 (12)	1	40	25
Natural Gas	100 (6)	1	20	50
Secondary Air	1000 (60)	1	200	5

Both the primary and tertiary air flows are supplied by the shop air which has a combined maximum flow capacity of approximately 450 SLPM (27 m^3/hr or 31.97 kg/hr). The secondary air is supplied by an air blower shown in figure 29 that has an advertised maximum capacity of 1100 SLPM (66 m^3/hr or 78.14 kg/hr); however, the air blower can only provide a maximum of 350 SLPM (21 m^3/hr or 24.86 kg/hr) of actual air flow through the gas flow meters.

Figure 29. 350 SLPM (21 m^3/hr or 24.86 kg/hr) Air Blower.

2. The solid fuel is fed by a Schenck-AccuRate Mechatron gravity feeder shown

in the following overview sketch (Figure 30) and picture (Figure 31). There are two feeders installed with the smaller capacity feeder calibrated to provide solid fuel flow rates of 1 to 12 lb/hr and the larger capacity feeder calibrated to provide 8 to 20 lb/hr. The motive air (air fed to the feeder) is constrained to a maximum 200 SLPM (12 m^3/hr or 14.21 kg/hr) with an optimum setting of 70 SLPM (4.2 m^3/hr or 4.97 kg/hr) for the large capacity feeder and a maximum of 110 SLPM (6.6 m^3/hr or 7.81 kg/hr) with an optimum setting of 50 SLPM (3 m^3/hr or 3.55 kg/hr) for the small capacity feeder based on experiments and analysis conducted by Coon et al. (2006).

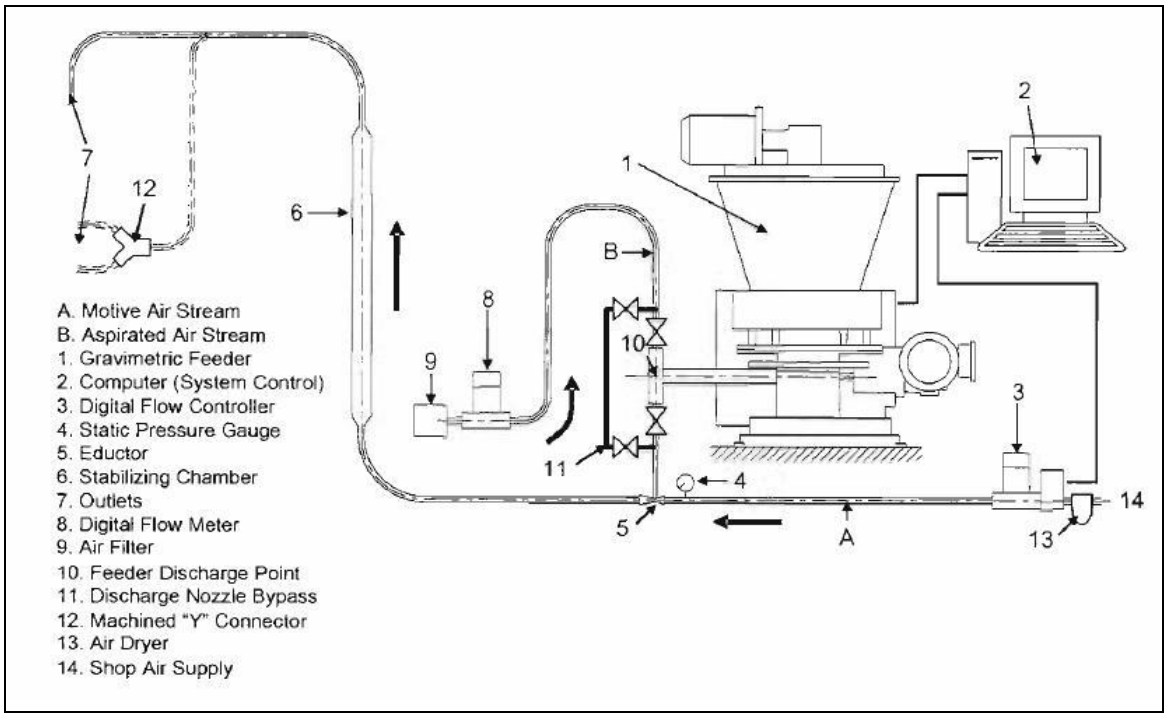

Figure 30. Diagram of Schenck AccuRate Mechatron feeder set-up. Adapted from Coon et al. (2006).

Figure 31. Schenck AccuRate Mechatron feeder.

Due to clogging issues with the gravimetric feeder, the end of the auger system was opened to atmospheric air pressure (recommended by an AccuRate technician) to ensure that a suction caused by the motive and entrainment air flows did not cause the pulverized coal to clog and cause damage to the feeder auger. The motive air, which carries the fuel flow and draws in the entrainment air with the pulverized coal, is controlled and measured by the gas flow meter; however, the entrainment air which is drawn in from the open system at the end of the feeder cannot be controlled or measured by a gas flow meter. To ensure that the primary air flow rate was accurately estimated, the motive air was measured and the entrainment air was estimated using the following scheme. The motive gas is fixed at 70 SLPM (4.2 m3/hr or 4.97 kg/hr) for optimum feeder operation for this test as well as for all pulverized coal feeding rates. Nitrogen was then used as the motive gas. All other air flows were turned off. Due to the addition of air through entrainment with the motive N_2, the oxygen percentage in the mixed

exhaust stream changes. The gas analyzer measured approximately 13.9% O_2 in the exhaust gas stream. Based on this measurement and the measured motive flow of the nitrogen, the entrainment air flow was calculated using the following mass conservation equation in kmol:

$$a\ N_2 + b\ (O_2 + 3.76\ N_2)_{\text{Entrainment Air}} \rightarrow (a + 3.76b)\ N_2 + b\ O_2$$

Solving the oxygen balance reaction yields b = 0.139 and solving the nitrogen balance yields a = 0.861-(0.139)*(3.76) = 0.33836, which results in the following balanced reaction in kmol:

$$0.33836\ N_2 + 0.139\ (O_2 + 3.76\ N_2) \rightarrow 0.139\ O_2 + 0.861\ N_2$$

Normalizing this equation to 1 kmol of nitrogen produces the following:

$$N_2 + 0.4108\ (O_2 + 3.76\ N_2) \rightarrow 0.4108\ O_2 + 2.5446\ N_2$$

Based on the measured N_2 flow of 70 SLPM (4.2 m3/hr or 4.97 kg/hr), the N_2 flow rate was calculated using the following conversions assuming standard temperature and pressure conditions:

$$(70\ \text{L/min})*(\text{m}^3/1000\ \text{L})*(1\ \text{kmol}_{N2} / 24.5\ \text{m}^3) = 0.0028571429\ \text{kmol}_{N2}/\text{min}$$

Multiplying this rate through the above balanced reaction yields:

$$0.00285714\ N_2 + 0.00117373\ (O_2 + 3.76\ N_2) \rightarrow 0.00117373\ O_2 + 0.00727036\ N_2$$

Based on the entrainment flow in kmol/min, the following conversion yields the approximate entrainment flow:

$$\text{Air Entrainment Flow} = (0.00117373\ \text{kmol}_{\text{Air}}/\text{min})\ (24.5\ \text{m}^3/\text{kmol}_{\text{Air}})*(1000\ \text{L}/\text{m}^3)$$

$$\text{Air Entrainment Flow} = 28.76\ \text{L}_{\text{Entrainment Air}}/\text{min}\ (1.73\ \text{m}^3/\text{hr or } 2.04\ \text{kg/hr})$$

Since the total primary air is a sum of the motive and entrainment air, the total primary air flow needs to be corrected to 70 + 28.76 (4.76) = 206.9 SLPM (12.42 m3/hr or 14.71 kg/hr) for use in the total air calculations and combustion experiments which yields an approximate 1.8 PA/PC ratio.

3. Both the secondary air and tertiary air were preheated prior to entering the combustion chamber of the furnace as shown in figure 32 below. The secondary air's three-quarter inch steel pipes were heated by a 1440 Watt heating element while the tertiary air's one-half inch steel pipes were heated by a 432 Watt heating element. Both heating elements were operated at 50 percent capacity in order to avoid damaging the heating element itself while conducting experiments lasting several hours.

Figure 32. Secondary and tertiary air BriskHeat XtremeFlex multi-use heating tapes.

Based on experiments with various air flow rates with the heating elements set at 50 percent capacity, the heating elements are able to raise the temperature of the secondary air from a minimum of 383.15 K (230ºF) at 300 SLPM (18 m^3/hr or 21.31

kg/hr) to a maximum of 464.26 K (376ºF) at 40 SLPM (2.4 m^3/hr or 2.84 kg/hr) and raise the temperature of the tertiary air from a minimum of 319.26 K (115ºF) at 210 SLPM (12.6 m^3/hr or 14.92 kg/hr) to a maximum of 329.82 K (134ºF) at 80 SLPM (4.8 m^3/hr or 5.68 kg/hr).

Modifying the First Law of Thermodynamics yields a prediction for the final temperature of the air based on varying air flow rates:

$$dE/dt = \dot{Q} - \dot{W}_{electric} + \dot{m}\ (h_1 - h_2)$$

Assuming steady state conditions (dE/dt = 0), adiabatic conditions ($\dot{Q} = 0$), and constant specific heats where (h_1-h_2) = Cp (T_1-T_2), the above equation simplifies to obtain the following:

$$\dot{W}_{electric} = \dot{m}\ Cp\ (T_2 - T_1)$$

where,

$\dot{m}$ - air mass flow based on secondary or tertiary air flow (kg/sec)

Cp ~ 1.004 kJ/kg·K

T_1 - atmospheric temperature ~ 298.15 K or 25ºC

$\dot{W}_{electric}$ - work input (kW)

Solving this equation yields T_2 or the maximum calculated temperature possible for each secondary and tertiary air flow and their respective heating element capacities. The following figure 33 and figure 34 are graphs comparing the measured maximum temperatures for varying air mass flow rates versus the calculated temperatures at the same flow rates:

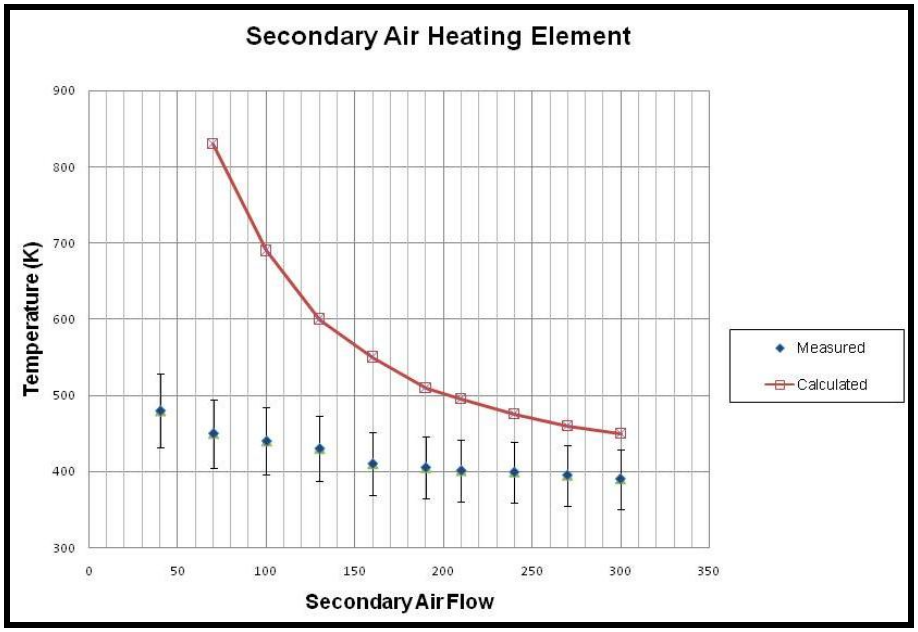

Figure 33. Measured vs. calculated secondary air temperatures at various flow rates.

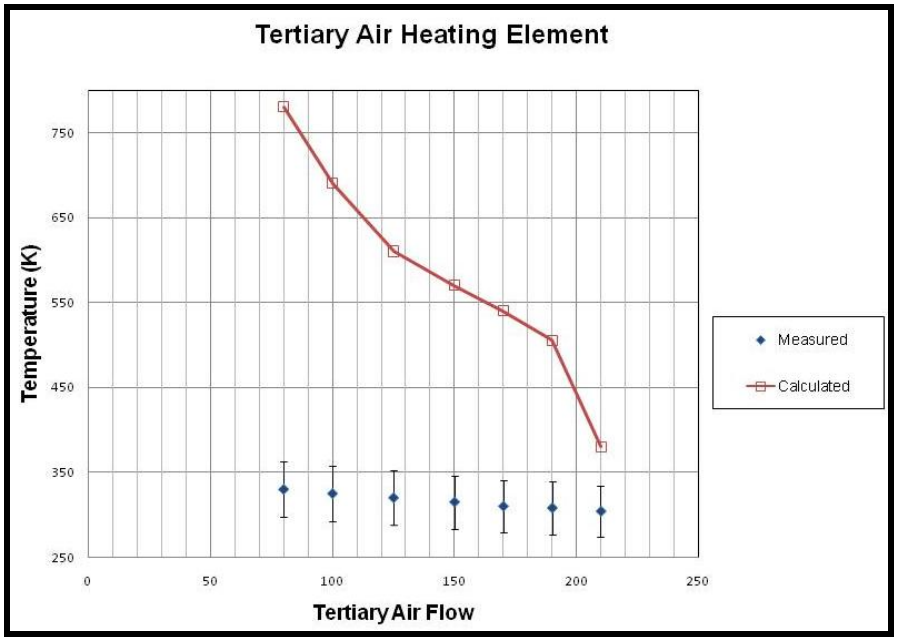

Figure 34. Measured vs. calculated tertiary air temperatures at various flow rates.

The discrepancy between the actual measured values and the calculated values based on the First Law of Thermodynamics is due to the assumptions, such as the assumption of the adiabatic heater, that were used to simplify the first law equation to get the calculated values.

To determine the temperature of the air entering the furnace, one thermocouple is installed on each of the secondary and tertiary air lines as shown in figure 35. There are also eleven thermocouples placed vertically down the furnace beginning six inches below the furnace nozzle and spaced six inches apart all the way down to the sample port location.

Figure 35. Thermocouple locations on the 100,000 BTU/hr furnace.

Figure 36 shows the thermocouples connected to a Measurement Computing USB-TC 8 channel thermocouple input module that converts the thermocouple inputs into digital data that can be read and displayed by LabVIEW.

Figure 36. USB-TC thermocouple data transfer device.

The sampled port located 66 inches below the nozzle is connected to the Eurotron Instruments Greenline 8000 Gas Analyzer shown in figure 37. The gas analyzer measures the exhaust gas composition and provides a digital and printed summary for the amount of O_2, CO, CO_2, NO_x, SO_2, and C_xH_y found in the exhaust gases.

Figure 37. Eurotron Instrument Greenline 8000 Gas Analyzer connected to the bottom burner sample port.

EXPERIMENTAL PROCEDURE

To validate the reduction of NO_x emissions using WYO and dairy biomass fuel blends, experiments were conducted on a small scale low-NO_x coal-fired boiler burner at CBEL in TAMU.

The following steps are used to prepare the furnace for the solid fuel combustion:

1. Prepare the furnace for firing:
    a. Inspect the furnace to ensure that it is sealed so that air is not able to get inside of the furnace and ruin experimental data.
    b. Turn on the exhaust fan and open the furnace exhaust vent port to ensure slightly negative pressure inside the furnace and to clear any combustible gas residue within the furnace.
    c. Turn the water pump and water spray on at the exhaust vent location to ensure exhaust gases are cooled prior to exiting through the exhaust.
2. Turn on control devices and air flows:
    a. Turn on the gas flow meters and run the LabVIEW program to check flow meter operation and thermocouple inputs.
    b. Ensure that the primary, secondary, and tertiary air lines are open.
    c. Turn on primary and secondary air flows. To ignite the furnace with NG, the optimum settings for the primary air is 70 SLPM (4.2 m^3/hr or 4.97 kg/hr) and for the secondary air is 140 SLPM (8.4 m^3/hr or 9.95 kg/hr).

d. Turn on the heating element for the secondary air line only. Do not operate heaters without air flow or the heating elements will overheat.

3. Ignite the furnace:

a. Place the propane torch at the nozzle location with flame oriented toward the center of the burn chamber (Figure 38).

Figure 38. Propane torch being used to ignite the furnace.

b. Open the NG valve. NG flow setting should read approximately 40 SLPM (2.4 m^3/hr or 2.84 kg/hr) for the air flows given above.

c. Once the NG is burning, increase the primary air flow to 140 LPM.

d. Turn off the propane torch when temperatures average greater than 1300 degrees Fahrenheit for the second and third thermocouples located 12 inches and 18 inches respectively from the nozzle.

e. Once the propane torch has been removed from the furnace hole located on top of the furnace, the hole is sealed with a screw covered with hardened sealant that creates a seal and prevents air from

entering the hole into the furnace.

4. Prepare for solid fuel feeding:
    a. Once temperatures stabilize around 2200ºF (1478 K) which generally takes about two hours, the pulverized coal is ready to be fed into the furnace.
    b. Turn off the NG flow and close the NG valve located at the top of the furnace to ensure solid fuel does not go into the NG line.
    c. Ensure that the primary air flow (motive air flow) is set at 70 SLPM (4.2 m^3/hr or 4.97 kg/hr) for optimum feeder operation. Set the secondary and tertiary air flows to the required air flows based on the calculated fuel feed rates.
    d. Turn on the Mechatron gravity feeder, ensure that it is connected to the correct feeder used for the experiment, and set the required fuel feed rate in lbs/hr.
    e. Fill the feeder hopper with the solid fuel being fired into the furnace. To avoid auger clogging issues, the maximum weight of fuel placed in the hopper should not exceed 24 pounds.
    f. To refill the hopper once the feeder has begun feeding the solid fuel, activate the fill start command to ensure that the RPM is maintained at a constant rate while filling the hopper with additional fuel. Once refilling is complete, wait approximately 60 seconds to allow the coal to settle in the hopper and activate the fill stop command.

5. Connect the Gas Analyzer to the sample port to measure exhaust gas concentrations. The analyzer has a digital display of real time concentrations. Allow some time to ensure that temperatures, fuel feed rates, and oxygen output levels stabilize once changes have been made. Once changes were made during these experiments, the combustion process was allowed to stabilize for a minimum of 10 minutes before measurements were taken. "The *in situ* measurements (e.g., CO_2, NO, CO, etc.) involve direct measurements of flue gas, usually on a wet basis" (Annamalai et al., 2007). The gas analyzer provides print outs of the measured exhaust gas concentrations.
6. Prepare for shutting down and cooling the furnace:
    a. Once experiments have been completed, turn off the feeder to stop the flow of solid fuel.
    b. Open the exhaust vents all the way, increase the air flows, and turn off all heaters. Do not turn off the exhaust water pump and spray until temperatures recorded by thermocouples reach less than 800^{o}F.
    c. Once the furnace has been given some time to cool down, remove the port windows to allow air to enter and cool the furnace faster.

UNCERTAINTY AND REPEATABILITY ANALYSIS

There are many uncertainties found within these experiments as shown in table 3 below. The chemical empirical formula based on the fuel properties given for the WYO and LA-PC-DB-SepS may not always be constant due to the fuel blends not being blended sufficiently in the feeder or changes in moisture content that may have affected portions of the fuels burned; therefore, the stoichiometric calculations used to find the required air flows at specific equivalence ratios had some uncertainty. The other uncertainty in this experiment was the procedure used for mixing time estimation for tertiary air mixing and the fact that only CO_2 was used to test the LNB's staging effect on the tertiary flow mixing with the fuel. This test was conducted under cold conditions (without combustion) at room temperature measuring the amount of CO_2 mixing that occurred at the center of the furnace 6 and 12 inches below the burner nozzle location. Since radial profiles of CO_2 are not obtained, there is a certain degree of uncertainty in estimating mixing time.

One measured uncertainty found was with the gravimetric feeder that had a manufacturer's uncertainty of ¼ % for gravimetric flow but was observed to have an actual measured uncertainty of +/- 3.12 %. All the air flow meters also contributed uncertainty to the actual total air flow that reacted with each given fuel feed rate at different equivalence ratios. The motive air flow meter had an approximate uncertainty of +/- 7.14 %, the secondary air flow meter had an approximate uncertainty of +/- 2.68 %, and the tertiary air flow had the highest uncertainty at +/- 12.37 %. Another uncertainty is that the flow of the solid fuel in the motive air may decrease the

entrainment air flow which was estimated based on pure gas flow measurements. The entrainment air was measured to be 136.9 SLPM using N_2 as the motive air without any coal flow. Changing the coal feed rate may also increase or decrease the actual entrainment air flowing in as part of the primary air. The estimated uncertainty for the entrainment air was +/- 3.48 %; however, this uncertainty may actually be higher due to the fact that there is no way to currently measure the entrainment air flow. The unstable exhaust gas stream measurements were the final factor that contributed an uncertainty of +/- 10.63 %.

Table 3. Uncertainty Factors.

Uncertainty Factor	% Uncertainty for each factor	
Gravimetric Feeder	+/-	3.12
Motive Air Flow Meter	+/-	7.14
Entrainment Air Flow (not measured)	+/-	3.48
Secondary Air Flow Meter	+/-	2.68
Tertiary Air Flow Meter	+/-	12.37
Data Measurement	+/-	10.63

Based on the approximation for calculating the uncertainty interval by Kline et al. (1953) and uncertainty analysis by Oh (2008), the overall system uncertainty was determined to be +/- 9.30 % with the uncertainty from the tertiary air flow and the data measurement being the predominant uncertainty factors.

The repeatability was estimated with a second experiment using the same fuel blends with similar experimental parameters. The second experiments had an overall

system uncertainty of +/- 12.04 % due to the data measurement's increased uncertainty equal to 18.63 %.

CHAPTER V

RESULTS AND DISCUSSIONS

The following section provides the analysis conducted on the WYO and LA-PC-DB-SepS fuels used for this research. The first section shows the completed ultimate and proximate analysis of the fuels as well as the results of fuel particle size distribution analysis. The next section provides the results of burning unstaged WYO, which was used as the base case coal, without the DB to get base measurements on the LNB furnace's performance and effect on NO_x production. These results were then compared to the LNB furnace's effect on NO_x when firing the staged WYO.

All experiments were conducted for equivalence ratios (ϕ) from 0.8 to 1.2. Results are shown for the WYO blended with the LA-PC-DB-SepS fuel in 95:5, 90:10, 85:15, and 80:20 blends on a mass basis. The parametric studies were completed for all fuel blends cofired in unstaged (using primary and secondary air only) and staged (using primary, secondary and tertiary air) conditions.

For the parametric study on varying equivalence ratios, two sets of experiments were also conducted to determine the effects, if any, varying air flow at a constant fuel feed rate or heat output would have on NO_x production as compared to varying the fuel feed rate or heat output at a set or constant air flow. The first experiment was completed maintaining a constant fuel feed rate or heat output of 100,000 BTU/hr while adjusting the air flow to change the equivalence ratios. The second experiment was completed maintaining a constant air flow which was set at stoichiometric conditions (100% of

theoretical air) required for each fuel blend feed rate that provided a heat output of 100,000 BTU/hr. The fuel feed rate was then adjusted to change the equivalence ratio with a constant air flow.

FUEL PROPERTIES

Ultimate and Proximate Analysis

Thien (2002) and Lawrence (2007) described in detail how the LA-PC-DB-SepS was harvested, composted and prepared for use in cofiring experiments. Hazen Laboratories in Colorado preformed the ultimate and proximate analysis on all fuel samples.

Based on a heat basis comparison, the LA-PC-DB-SepS fuel contains approximately 4.17 times the amount of nitrogen, approximately 2.33 times the amount of oxygen, and approximately 3.73 times the amount of ash than the WYO coal as shown in table 4. The LA-PC-DB-SepS also contains approximately 2.33 times the amount of volatile matter than the WYO samples. Because of the higher inherent nitrogen, oxygen, and VM in the LA-PC-DB-SepS, NO_x formation would appear to be much higher than the WYO coal.

Table 4. Ultimate and Proximate Fuel Analysis. Adapted from Lawrence (2007).

	LA-PC-DB-SepS	**WYO**
Proximate Analysis		
Dry Loss (% Moisture)	25.26	32.88
Ash	14.86	5.64
FC	13.00	32.99
VM	46.88	28.49
Ultimate Analysis		
Carbon, C	35.21	46.52
Hydrogen, H	3.71	2.73
Nitrogen, N	1.93	0.66
Oxygen, O (diff)	18.60	11.29
Sulfur, S	0.43	0.27
HHV (kJ/kg) As Received	12,844.17	18,193.02
HHV (kJ/kg) Dry	17,185.90	27,106.57
HHV (kJ/kg) DAF	21,449.85	29,593.38
HHV (kJ/kg of stoich Air) As Received	2,886.07	3,191.89
Boie HHV (kJ/kg)	14,799.49	18,347.96
A:F As Received	4.45	5.73
A:F DAF	7.44	9.40
FC DAF	21.72	53.66
VM DAF	78.28	46.34
Ash kg/GJ	11.57	3.10
FC kg/GJ	10.12	18.13
VM kg/GJ	36.50	15.66
Nitrogen kg/GJ	1.50	0.36
Oxygen g/GJ	14.48	6.21
Sulfur kg/GJ	0.33	0.15
Chemical Formula	$CH_{1.255424}N_{.046999}O_{.396524}S_{.004573}$	$CH_{.699206}N_{.012165}O_{.18217}S_{.002174}$
$T_{adiabatic}$ (K), $\phi = 0.9$	1814.78	2088.45
$T_{adiabatic}$ (K), $\phi = 1$	1923.06	2223.54
$T_{adiabatic}$ (K), $\phi = 1.1$	1799.81	2118.49
Ash Loading (kg/GJ)	8.14	2.00

Fuel Feed Rate

Based on the given properties for each fuel, the theoretical air required for pure WYO fuel as well as for each WYO:DB fuel blend was calculated. The empirical chemical formula was normalized with respect to carbon in order to get one unit atom of carbon in the fuel. The following are the equations used to conduct the proximate analysis of the pure WYO on a "wet" basis:

$C = \%\ C / M_{Carbon} = 46.52 / 12.01 = 3.87$

$C_{normalized} = 3.87 / 3.87 = 1.00$

$H = \%\ H / (M_{Hydrogen} * C) = 2.73 / (1.008 * 3.87) = 0.699$

$N = \%\ N / (M_{Nitrogen} * C) = 0.66 / (14 * 3.87) = 0.0122$

$O = \%\ O / (M_{Oxygen} * C) = 11.29 / (16 * 3.87) = 0.182$

$S = \%\ S / (M_{Sulfur} * C) = 0.27 / (32.07 * 3.87) = 0.00217$

The carbon normalized empirical formula of WYO based on the proximate analysis is determined to be $CH_{0.699}N_{0.0122}O_{0.182}S_{0.00217}$ which has a molecular weight of 15.87 kg/kmol. For 100,000 BTU/hr (29.31 kW) of power, the fuel mass flow rate based on the WYO fuel heating value is calculated using the following equation:

Power (kW) = $\dot{m}$ (kg/sec) * HHV (kJ/kg)

$\dot{m}_{As\ Received\ (WYO)}$ = Power / $HHV_{As\ Received}$ = 29.31 (kJ/s) / 18,193.02 (kJ/kg)

= 0.001611 kg/sec = 12.8 lb/hr (5.8 kg/hr)

Similar procedures were used to calculate the mass flow rates for the different WYO:DB fuel blends using the $HHV_{Mixture}$. The $HHV_{Mixture}$ was calculated using the following equation:

$HHV_{Mixture}$ = (% WYO/100)*18,193.02 (kJ/kg) + (% DB/100)*12,844.17 (kJ/kg)

The $HHV_{Mixture}$ was used to calculate the total fuel feed rate required for each specified WYO:DB fuel blend.

Fuel Particle Size Analysis

The coal samples were acquired from TXU, and the LA-PC-DB-SepS samples were acquired from Heflin et al. (2006). Approximately 333 grams of WYO fuel and 357 grams of LA-PC-DB-SepS fuel samples were each shaken in a CE Tyler Roto-Tap model B (approved by ASTM standard C136-06) and passed through the stack of sieves to determine the SMD for each fuel type in a process described by Lawrence (2007). The following table 5 and table 6 show the results for each fuel type:

Table 5. Data from shaking WYO.

Mesh #	Sieve Diameter d_p (μm)	bigger than (g)	ΔY_p (%)	less than (%)	Mean d_p (μm)
10	2000	0.001	0.00030019	99.9997	2000.00
16	1190	0.153	0.04592898	99.9538	1595.00
20	840	0.224	0.06724243	99.8865	1015.00
50	300	6.113	1.83505792	98.0515	570.00
100	150	101.857	30.57639370	67.4751	225.00
200	75	154.441	46.36155414	21.1135	112.50
325	45	40.753	12.23361941	8.8799	60.00
Pan	0	29.581	8.87990322		22.50
		333.123	grams		

Table 6. Data from shaking LA-DB-PC-SepS.

Mesh #	Sieve Diameter d_p (μm)	bigger than (g)	ΔY_p (%)	less than (%)	Mean d_p (μm)
10	2000	0.179	0.05013767	99.9499	2000.00
16	1190	0.675	0.18906663	99.7608	1595.00
20	840	1.441	0.40362224	99.3572	1015.00
50	300	27.122	7.59683713	91.7603	570.00
100	150	52.675	14.75419938	77.0061	225.00
200	75	95.467	26.74018324	50.2660	112.50
325	45	70.966	19.87748483	30.3885	60.00
Pan	0	108.492	30.38846890		22.50
		357.017	grams		

There were two methods used to calculate the SMD based on the above fuel sieve data. Method A uses the following equation to calculate the SMD from direct sieve analysis and is defined by Annamalai et al. (2007) as the volume-to-surface area ratio for all droplets:

$$SMD = 1 / \sum (\Delta Y_p / d_p)$$

where,

ΔY_p is the mass fraction between the sieve diameter sizes (μm)

d_p is the particle or drop size (μm)

Method B used the Rosin-Rammler curve fit estimation, which is used widely for pulverized solid and liquid fuels, to determine the SMD.

The mass which passed through the last sieve into the pan was excluded in both estimations of SMD. The following table 7 shows the calculated size distribution parameters based on the fuel shaking data and the methods described above:

Table 7. Size distribution parameters (excludes pan mass %).

	WYO	LA-PC-DB-SepS
n	1.262079	0.788975
b	0.001277	0.023044
METHOD A: SMD (microns)	120.6604	107.3739
METHOD B: SMD (microns)	112.7904	98.28248

"Typically, for coal-fired burners, about 70% of mass passes through 75-µm (200 mesh) sieves" (Annamalai et al., 2007). Lawrence (2007) found that "solid fuels with less than 69% FC and a HHV less than 11,000 BTU/lb need to be ground to 60% less than ASTM mesh 200 (74 microns)." The LA-PC-DB-SepS had a smaller SMD than the WYO with a 70% mass through 150.6 microns with an $HHV_{LA\text{-}PC\text{-}DB\text{-}SepS\ (As\ Received)}$ of 5,522.04 BTU/lb. The WYO had a greater SMD with a 70% mass through 227.5 microns with $HHV_{WYO\ (As\ Received)}$ of 7,821.64 BTU/lb. Neither of the fuels was ground to less than 70% of mass passing through 75 microns as shown in the following fuel size distribution plot on figure 39:

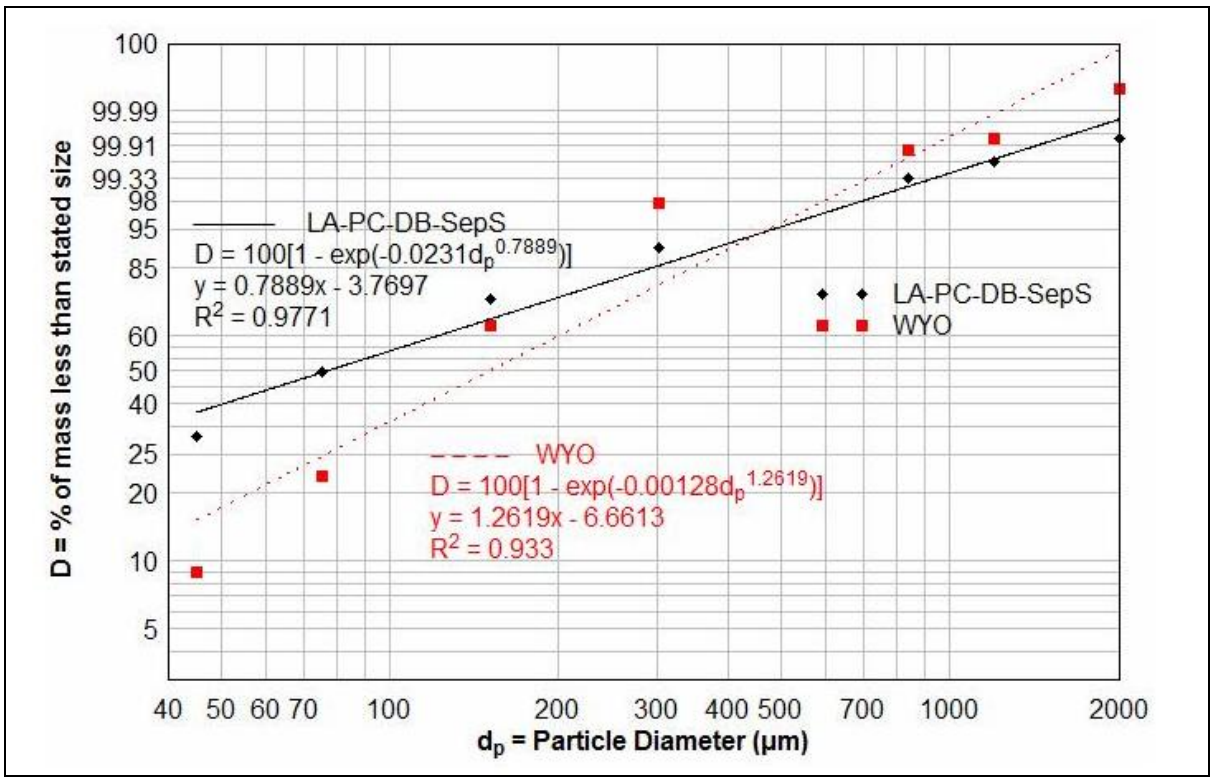

Figure 39. Particle size distribution on a log-log scale of WYO and LA-PC-DB-SepS fuels.

EXPERIMENTAL PARAMETERS

WYO was used as the base case coal. The WYO was blended with the LA-PC-DB-SepS fuel in 95:5, 90:10, 85:15, and 80:20 blends on a mass basis. The pure WYO was burned in the newly constructed LNB furnace to test the operational capability of the furnace. These results were then used as the baseline data to determine the effects of equivalence ratio (ϕ), cofiring of the biomass fuel blends, and air staging (splitting the unstaged secondary air into secondary and tertiary air flows while maintaining a constant primary air flow) on NO_x production.

For the parametric study on varying the equivalence ratios, two sets of experiments were conducted to determine the effects, if any of the following:

(i) Varying air flow to adjust equivalence ratios at a constant fuel or heat output of 100,000 BTU/hr, and

(ii) Varying the fuel feed rate or heat output to adjust the equivalence ratio at a constant air flow. The constant air flow is maintained at the stoichiometric air flow required for a fuel feed rate or heat output of 100,000 BTU/hr.

The unstaged, pure WYO was fired with a mass flow rate of 5.85 kg/hr (12.89 lb/hr) to produce a heat output of 100,000 BTU/hr with a calculated as received stoichiometric A:F ratio of 5.73. This required a total air flow of 471.65 LPM (28.3 m^3/hr or 33.51 kg/hr). The total air was then divided into 98.76 LPM (5.93m^3/hr or 7.02 kg/hr) of primary air making up approximately 21 percent of the total air flow and 372.89 LPM (22.37 m^3/hr or 26.49 kg/hr) of secondary air making up approximately 79 percent of the total air flow required. Firing the WYO at the calculated fuel feed rate required to produce 100,000 BTU/hr, the secondary air was adjusted to minimize oxygen concentration in the exhaust gas stream to approximate stoichiometric conditions as closely as possible. The following table 8 shows the air flow settings used for the pure WYO combustion experiments with constant fuel feed rate / heat output:

Table 8. Experimental Parameters for unstaged pure WYO with constant fuel feed rate / heat output of 100,000 BTU/hr.

% FUEL BLEND	Equivalence Ratio	Fuel Flow Rate kg/hr (lb/hr)	Primary Air	Secondary Air	Total Air Required		A:F	Secondary / Total (%)
			(LPM)	(LPM)	(m^3/hr)	(kg/hr)		
100:0	0.8	5.845 (12.89)	98.76	490.79	35.37	41.88	7.16	83.25
	0.9	5.845 (12.89)	98.76	425.28	31.44	37.23	6.36	81.15
	1	5.845 (12.89)	98.76	372.88	28.30	33.51	5.73	79.06
	1.1	5.845 (12.89)	98.76	330.00	25.73	30.46	5.21	76.97
	1.2	5.845 (12.89)	98.76	294.27	23.58	27.92	4.77	74.87

For all experiments, the secondary air was heated. The following table 9 shows the secondary air temperature recorded for each equivalence ratio for the pure WYO experiments with constant fuel feed rate / heat output:

Table 9. Secondary air temperature preheat measurements.

% FUEL BLEND	Equivalence Ratio	Secondary Air	Temperature
		(LPM)	F (K)
100:0	0.8	490.79	181 (356)
	0.9	425.28	190 (361)
	1	372.88	198 (365)
	1.1	330.00	208 (371)
	1.2	294.27	213 (374)

Parametric studies of the pure WYO were also conducted by changing the fuel feed rate (mass flow rate) or heat output to adjust the equivalence ratios while maintaining constant air flow rates based on the calculated theoretical air at stoichiometric conditions. The following table 10 shows the varying fuel flows used for the pure WYO combustion experiments with the constant air flow:

Table 10. Experimental Parameters for unstaged pure WYO with constant air flow.

% FUEL BLEND	Equivalence Ratio	Fuel Flow Rate kg/hr (lb/hr)	Primary Air	Secondary Air	Total Air Required		A:F	Secondary / Total (%)
			(LPM)	(LPM)	(m^3/hr)	(kg/hr)		
100:0	0.8	4.68 (10.32)	98.76	362.00	27.65	32.73	6.99	78.57
	0.9	5.27 (11.61)	98.76	362.00	27.65	32.73	6.22	78.57
	1	5.85 (12.90)	98.76	362.00	27.65	32.73	5.60	78.57
	1.1	6.44 (14.19)	98.76	362.00	27.65	32.73	5.09	78.57
	1.2	7.02 (15.48)	98.76	362.00	27.65	32.73	4.66	78.57

The temperature of the secondary air remained constant at approximately 211^{o}F (373 K) for experiments utilizing the constant air flows.

Once the WYO base case had been evaluated, WYO:DB fuel blends were then evaluated for 95:5, 90:10, 85:15, and 80:20 fuel blends as shown for both unstaged conditions as shown in table 11 and table 12.

Table 11. Experimental Parameters for unstaged WYO:DB fuel blends for constant fuel feed rate / heat output of 100,000 BTU/hr.

% FUEL BLEND	Equivalence Ratio	Fuel Flow Rate (kg/hr)	Primary Air * (LPM)	Secondary Air (LPM)	Total Air Required (m3/hr)	Total Air Required (kg/hr)	A:F	Primary / Total (%)	Secondary / Total (%)
100:0 Unstaged	0.8	5.85	98.76	583.25	39.19	46.41	7.94	10.72	89.28
	0.9	5.85	98.76	510.67	34.84	41.25	7.06	12.06	87.94
	1	5.85	98.76	452.60	31.36	37.13	6.35	13.39	86.61
	1.1	5.85	98.76	405.09	28.51	33.75	5.77	14.73	85.27
	1.2	5.85	98.76	365.50	26.13	30.94	5.29	16.07	83.93
95:5 Unstaged	0.8	5.93	98.76	517.50	35.25	41.74	7.04	11.91	88.09
	0.9	5.93	98.76	452.22	31.33	37.10	6.25	13.40	86.60
	1	5.93	98.76	400.00	28.20	33.39	5.63	14.89	65.11
	1.1	5.93	98.76	357.27	25.64	30.35	5.12	16.38	83.62
	1.2	5.93	98.76	321.67	23.50	27.82	4.69	17.87	82.13
90:10 Unstaged	0.8	6.02	98.76	523.75	35.63	42.18	7.01	11.79	88.21
	0.9	6.02	98.76	457.78	31.67	37.49	6.23	13.26	86.74
	1	6.02	98.76	405.00	28.50	33.74	5.61	14.74	65.26
	1.1	6.02	98.76	361.82	25.91	30.68	5.10	16.21	83.79
	1.2	6.02	98.76	325.83	23.75	28.12	4.67	17.68	82.32
85:15 Unstaged	0.8	6.11	98.76	467.50	32.25	38.18	6.25	13.02	86.98
	0.9	6.11	98.76	407.78	28.67	33.94	5.55	14.65	85.35
	1	6.11	98.76	360.00	25.80	30.55	5.00	16.28	63.72
	1.1	6.11	98.76	320.91	23.45	27.77	4.54	17.91	82.09
	1.2	6.11	98.76	288.33	21.50	25.46	4.16	19.53	80.47
80:20 Unstaged	0.8	6.21	98.76	420.00	29.40	34.81	5.61	14.29	85.71
	0.9	6.21	98.76	365.56	26.13	30.94	4.98	16.07	83.93
	1	6.21	98.76	322.00	23.52	27.85	4.49	17.86	62.14
	1.1	6.21	98.76	286.36	21.38	25.32	4.08	19.64	80.36
	1.2	6.21	98.76	256.67	19.60	23.21	3.74	21.43	78.57

Table 12. Experimental Parameters for unstaged WYO:DB fuel blends for constant air flow.

% FUEL BLEND	Equivalence Ratio	Fuel Flow Rate (kg/hr)	Primary Air (LPM)	Secondary Air (LPM)	Total Air Required (m3/hr)	Total Air Required (kg/hr)	A:F	Primary / Total (%)	Secondary / Total (%)
100:0 Unstaged	0.8	4.680	98.76	362.00	27.65	32.73	6.99	21.43	78.57
	0.9	5.265	98.76	362.00	27.65	32.73	6.22	21.43	78.57
	1	5.850	98.76	362.00	27.65	32.73	5.60	21.43	78.57
	1.1	6.435	98.76	362.00	27.65	32.73	5.09	21.43	78.57
	1.2	7.020	98.76	362.00	27.65	32.73	4.66	21.43	78.57
95:5 Unstaged	0.8	4.744	98.76	400.00	29.93	35.43	7.47	19.80	80.20
	0.9	5.337	98.76	400.00	29.93	35.43	6.64	19.80	80.20
	1	5.930	98.76	400.00	29.93	35.43	5.98	19.80	80.20
	1.1	6.523	98.76	400.00	29.93	35.43	5.43	19.80	80.20
	1.2	7.116	98.76	400.00	29.93	35.43	4.98	19.80	80.20
90:10 Unstaged	0.8	4.816	98.76	405.00	30.23	35.79	7.43	19.60	80.40
	0.9	5.418	98.76	405.00	30.23	35.79	6.61	19.60	80.40
	1	6.020	98.76	405.00	30.23	35.79	5.94	19.60	80.40
	1.1	6.622	98.76	405.00	30.23	35.79	5.40	19.60	80.40
	1.2	7.224	98.76	405.00	30.23	35.79	4.95	19.60	80.40
85:15 Unstaged	0.8	4.891	98.76	408.00	30.41	36.00	7.36	19.49	80.51
	0.9	5.503	98.76	408.00	30.41	36.00	6.54	19.49	80.51
	1	6.114	98.76	408.00	30.41	36.00	5.89	19.49	80.51
	1.1	6.725	98.76	408.00	30.41	36.00	5.35	19.49	80.51
	1.2	7.337	98.76	408.00	30.41	36.00	4.91	19.49	80.51
80:20 Unstaged	0.8	4.967	98.76	390.00	29.33	34.72	6.99	20.21	79.79
	0.9	5.588	98.76	390.00	29.33	34.72	6.21	20.21	79.79
	1	6.209	98.76	390.00	29.33	34.72	5.59	20.21	79.79
	1.1	6.830	98.76	390.00	29.33	34.72	5.08	20.21	79.79
	1.2	7.451	98.76	390.00	29.33	34.72	4.66	20.21	79.79

Once all fuel blends were burned with only primary and secondary air or under unstaged conditions, all fuel blends were then burned with staged air consisting of the primary, secondary and tertiary air flows in the LNB furnace. For staging, the primary air flow remained the same as the unstaged primary air flow. The unstaged secondary air flow was divided between the secondary and tertiary air flows. The secondary air was adjusted so that the combined primary and secondary air flows provided approximately 80% of the required air. This was based on current LNB parameters

being utilized with commercial LNB furnaces that were found to have a combined primary and secondary air percentage between 70% and 80% of the total theoretical air required. The following table13 and table 14 illustrate the experimental parameters for the staged combustion experiments for the constant fuel feed rate / heat output of 100,000 BTU/hr and for the constant air flow.

Table 13. Experimental Parameters for staged WYO:DB fuel blends for constant fuel feed rate / heat output of 100,000 BTU/hr.

% FUEL BLEND	Equivalence Ratio	Fuel Flow Rate (kg/hr)	Primary Air * (LPM)	Secondary Air (LPM)	Tertiary Air (LPM)	Total Air Required (m3/hr)	Total Air Required (kg/hr)	A:F	Tertiary / Total (%)
100:0 Staged	0.8	5.85	98.76	348.08	235.17	39.19	46.41	7.94	36.00
	0.9	5.85	98.76	348.08	162.59	24.84	41.25	7.06	28.00
	1	5.85	98.76	348.08	104.52	31.36	37.13	6.35	20.00
	1.1	5.85	98.76	348.08	57.01	28.51	33.75	5.77	12.00
	1.2	5.85	98.76	348.08	17.42	26.13	30.94	5.29	4.00
95:5 Staged	0.8	5.93	98.76	306.00	211.50	35.25	41.74	7.04	36.00
	0.9	5.93	98.76	306.00	146.22	31.33	37.10	6.25	28.00
	1	5.93	98.76	306.00	94.00	28.20	33.39	5.63	20.00
	1.1	5.93	98.76	306.00	51.27	25.64	30.35	5.12	12.00
	1.2	5.93	98.76	306.00	15.67	23.50	27.82	4.69	4.00
90:10 Staged	0.8	6.02	98.76	310.00	213.75	35.63	42.18	7.01	36.00
	0.9	6.02	98.76	310.00	147.78	31.67	37.49	6.23	28.00
	1	6.02	98.76	310.00	95.00	28.50	33.74	5.61	20.00
	1.1	6.02	98.76	310.00	51.82	25.91	30.68	5.10	12.00
	1.2	6.02	98.76	310.00	15.83	23.75	28.12	4.67	4.00
85:15 Staged	0.8	6.11	98.76	274.00	193.50	32.25	38.18	6.25	36.00
	0.9	6.11	98.76	274.00	133.78	28.67	33.94	5.55	28.00
	1	6.11	98.76	274.00	86.00	25.80	30.55	5.00	20.00
	1.1	6.11	98.76	274.00	46.91	23.45	27.77	4.54	12.00
	1.2	6.11	98.76	274.00	14.33	21.50	25.46	4.16	4.00
80:20 Staged	0.8	6.21	98.76	243.60	176.40	29.40	34.81	5.61	36.00
	0.9	6.21	98.76	243.60	121.96	26.13	30.94	4.98	28.00
	1	6.21	98.76	243.60	78.40	23.52	27.85	4.49	20.00
	1.1	6.21	98.76	243.60	42.76	21.38	25.32	4.08	12.00
	1.2	6.21	98.76	243.60	13.07	19.60	23.21	3.74	4.00

Table 14. Experimental Parameters for staged WYO:DB fuel blends for constant air flow.

% FUEL BLEND	Equivalence Ratio	Fuel Flow Rate (kg/hr)	Primary Air (LPM)	Secondary Air (LPM)	Tertiary Air (LPM)	Total Air Required (m3/hr)	Total Air Required (kg/hr)	A:F	Tertiary / Total (%)
100:0 Staged	0.8	4.680	98.76	269.85	92.15	27.65	32.73	6.99	20.00
	0.9	5.265	98.76	269.85	92.15	27.65	32.73	6.22	20.00
	1	5.850	98.76	269.85	92.15	27.65	32.73	5.60	20.00
	1.1	6.435	98.76	269.85	92.15	27.65	32.73	5.09	20.00
	1.2	7.020	98.76	269.85	92.15	27.65	32.73	4.66	20.00
95:5 Staged	0.8	4.744	98.76	300.25	99.75	29.93	35.43	7.47	20.00
	0.9	5.337	98.76	300.25	99.75	29.93	35.43	6.64	20.00
	1	5.930	98.76	300.25	99.75	29.93	35.43	5.98	20.00
	1.1	6.523	98.76	300.25	99.75	29.93	35.43	5.43	20.00
	1.2	7.116	98.76	300.25	99.75	29.93	35.43	4.98	20.00
90:10 Staged	0.8	4.816	98.76	304.25	100.75	30.23	35.79	7.43	20.00
	0.9	5.418	98.76	304.25	100.75	30.23	35.79	6.61	20.00
	1	6.020	98.76	304.25	100.75	30.23	35.79	5.94	20.00
	1.1	6.622	98.76	304.25	100.75	30.23	35.79	5.40	20.00
	1.2	7.224	98.76	304.25	100.75	30.23	35.79	4.95	20.00
85:15 Staged	0.8	4.891	98.76	306.65	101.35	30.41	36.00	7.36	20.00
	0.9	5.503	98.76	306.65	101.35	30.41	36.00	6.54	20.00
	1	6.114	98.76	306.65	101.35	30.41	36.00	5.89	20.00
	1.1	6.725	98.76	306.65	101.35	30.41	36.00	5.35	20.00
	1.2	7.337	98.76	306.65	101.35	30.41	36.00	4.91	20.00
80:20 Staged	0.8	4.967	98.76	292.25	97.75	29.33	34.72	6.99	20.00
	0.9	5.588	98.76	292.25	97.75	29.33	34.72	6.21	20.00
	1	6.209	98.76	292.25	97.75	29.33	34.72	5.59	20.00
	1.1	6.830	98.76	292.25	97.75	29.33	34.72	5.08	20.00
	1.2	7.451	98.76	292.25	97.75	29.33	34.72	4.66	20.00

EFFECT OF EQUIVALENCE RATIO FOR UNSTAGED WYO

The equivalence ratio (ϕ) was varied from 0.8 to 1.2 in increments of 0.1 for the following two cases: (1) adjusting the air flow with a constant fuel feed rate / heat output of 100,000 BTU/hr, and (2) adjusting the fuel feed rate / heat output with a constant air flow (the air flow is set at the stoichiometric air required for 100,000 BTU/hr heat output). For the base case WYO shown in figure 40, measurements for equivalence ratios of 0.8 were not able to be obtained due to the high air flow required which the current air blowers could not provide.

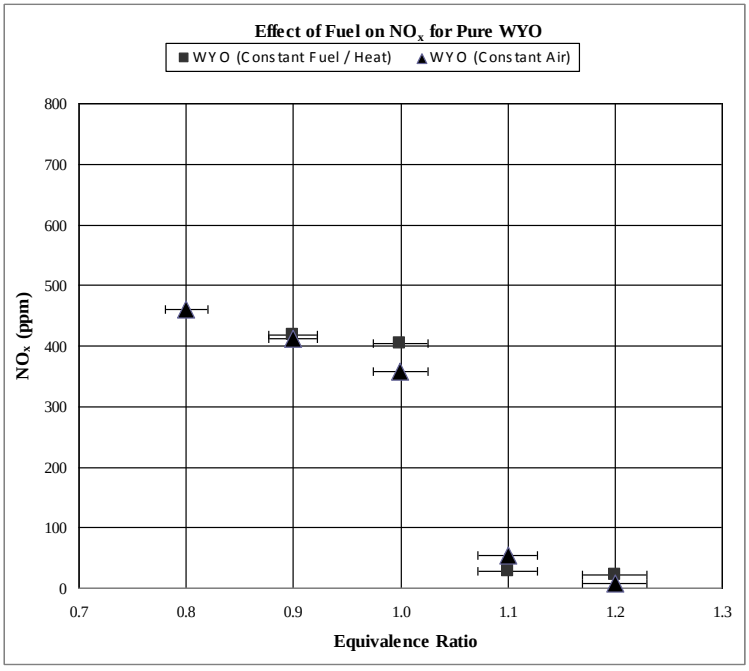

Figure 40. NO_x (ppm) emissions for unstaged WYO with constant air and constant fuel feed rate / heat output.

"If the mass of the emitted NO_x during a combustion process is held constant, then by simply increasing the amount of air supplied one can artificially reduce the NO mole fraction or ppm. Therefore, often the amount of NO emitted is normalized by the amount of O_2 provided to a combustor" (Annamalai et al., 2007); therefore the mole fraction of NO is corrected at a standard oxygen mole fraction which is 3% for utilities and is used in the following equation:

$$X_{NO,std} / X_{NO} = (X_{O2,a} - X_{O2,std}) / (X_{O2,a} - X_{O2})$$

where,

$X_{NO,std}$ = corrected NO mole fraction at standard oxygen mole fraction (ppm corrected to 3% O_2)

X_{NO} = uncorrected NO mole fraction (ppm)

$X_{O2,a}$ = ambient air mole fraction = 0.21

$X_{O2,std}$ = standard oxygen mole fraction = 0.03 or correction to 3% O_2

X_{O2} = measured oxygen mole fraction from exhaust gas stream

Figure 41 shows the NO_x (ppm corrected to 3% O_2) emissions:

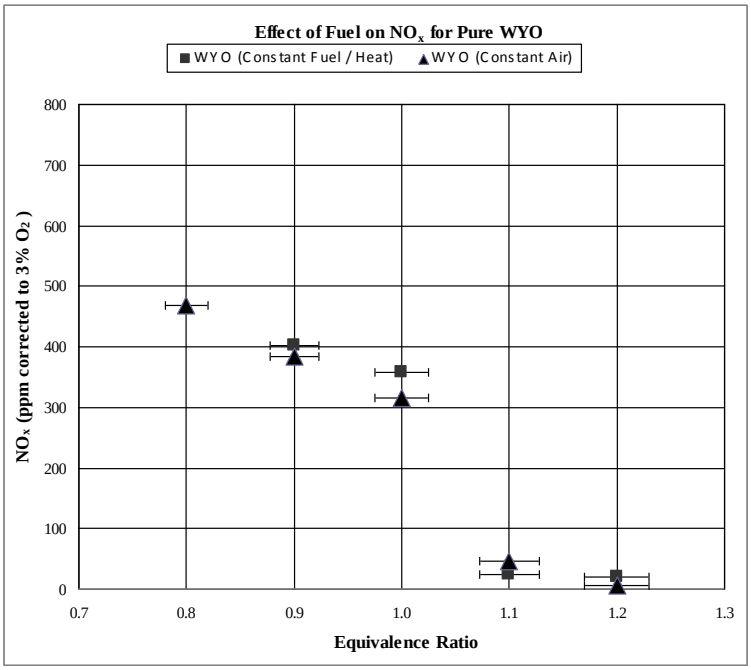

Figure 41. NO_x (ppm) emissions (corrected to 3% O_2) for unstaged WYO with constant air and constant fuel feed rate / heat output.

The following procedure used to convert NO_x in parts per million (ppm) to kilograms per Gigajoule (kg/GJ) is based on the assumption that all carbon reacts to form CO and CO_2 only and is taken from Annamalai et al. (2007):

$$NO \text{ in } g/GJ = c * X_{NO} * M_k * (1000 \text{ g/kg}) / (M_F * HHV_F * (X_{CO} + X_{CO2}))$$

where,

c = carbon molal concentration ($kmol/m^3$) based on the fuel's chemical empirical formula $C_cH_hO_oN_nS_s$

X_{NO} = NO_x in ppm (dry mole fraction)

$M_k = M_{NO2}$ = NO_2 molecular weight (kg/kmol) for NO on a mass basis

M_F = molecular weight of the fuel (kg/kmol)

HHV_F = Higher Heating Value of the fuel (GJ/kg) on a DAF basis

X_{CO} = CO mole fraction (dry)

X_{CO2} = CO_2 mole fraction (dry)

"For reporting NO emission, the U.S. Environmental Protection Agency (EPA) stipulates that M_k for NO should be that of NO_2 (M_{NO2} = 46.01) instead of 30 because NO is eventually converted into NO_2 in the atmosphere, which plays a major role in the destruction of O_3" (Annamalai et al., 2007). Figure 42 below shows NO_x (kg/GJ) emissions from pure WYO fired with constant fuel feed rate / heat output and constant air flows:

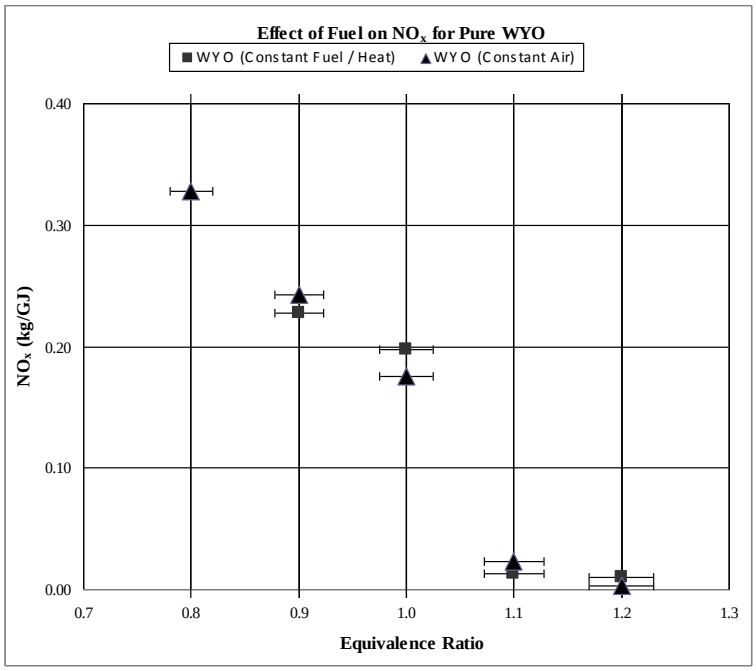

Figure 42. NO_x (kg/GJ) emissions for unstaged WYO with constant air and constant fuel feed rate / heat output.

The following figure 43 and figure 44 show the effects on CO_2 and CO emissions:

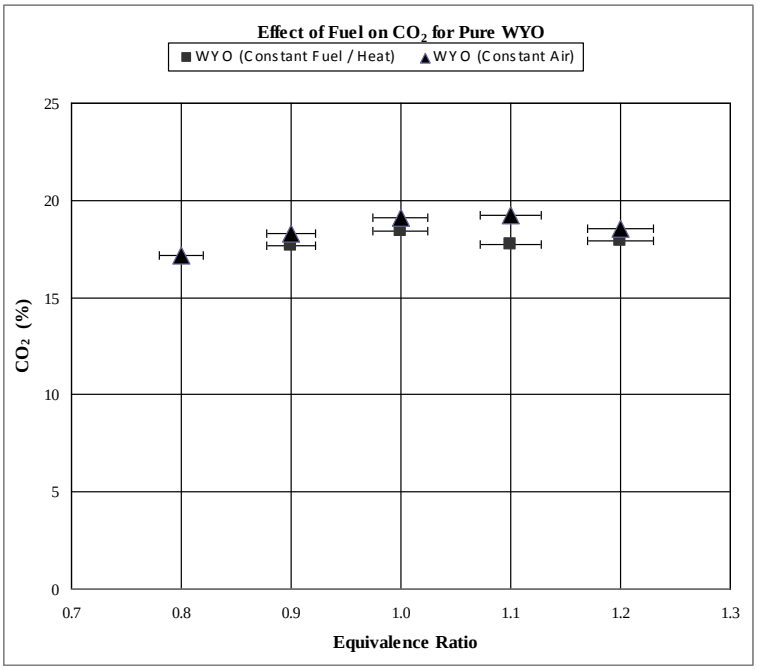

Figure 43. CO_2 (%) emissions for unstaged WYO with constant air and constant fuel feed rate / heat output.

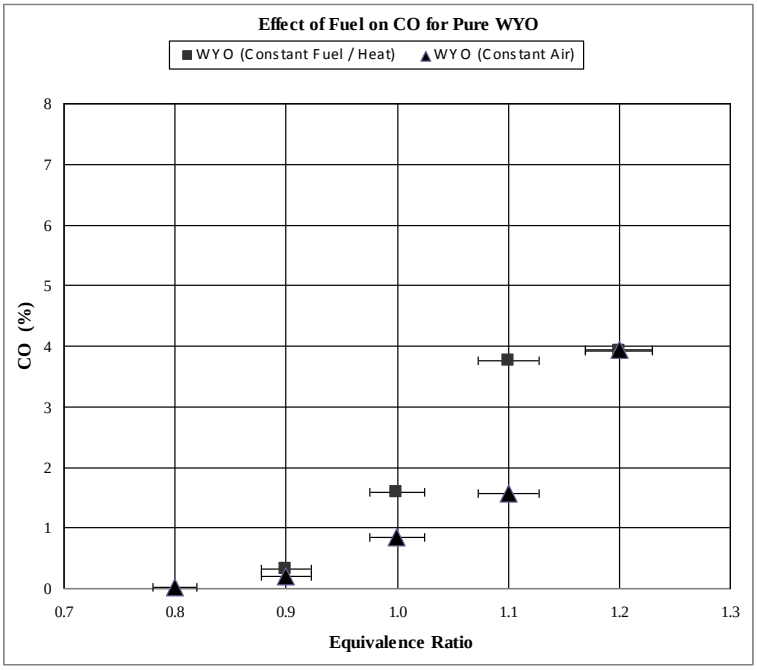

Figure 44. CO (%) emissions for unstaged WYO with constant air and constant fuel feed rate / heat output.

Based on the emissions recorded, changing the equivalence ratio for both sets of experiments for the unstaged WYO produced similar trends where NO_x production was very low in the rich regions and increased as more air was added from the rich to the lean regions. This was expected due to the additional oxygen available in the lean regions. CO production had the exact opposite trend seen in NO_x where CO was highest in the rich region, where incomplete combustion occurred, and then decreased down to zero in the lean regions as more oxygen was added ensuring complete combustion. CO_2 remained about the same or showed a slight increase in the rich region where incomplete combustion should have reduced CO_2 emissions due to incomplete combustion.

To determine why CO_2 emissions increased in the rich regions, the measured values were compared to estimated / calculated values based on the empirical chemical formula and the assumption that complete combustion occurs with equivalence ratios greater than or equal to 1.0. The following figure 45 and figure 46 show the measured values of CO and CO_2 with respect to their estimated values:

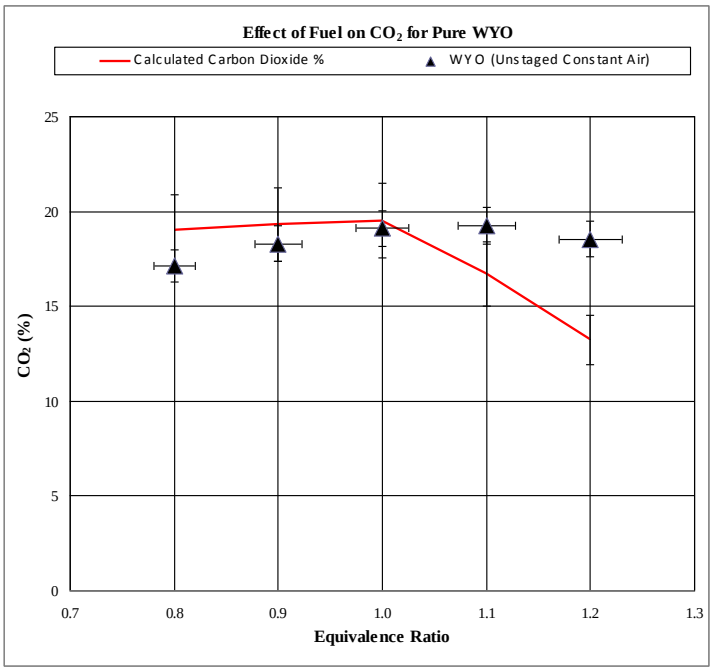

Figure 45. Calculated CO_2 (%) compared to actual CO_2 (%) emissions for unstaged WYO with constant air.

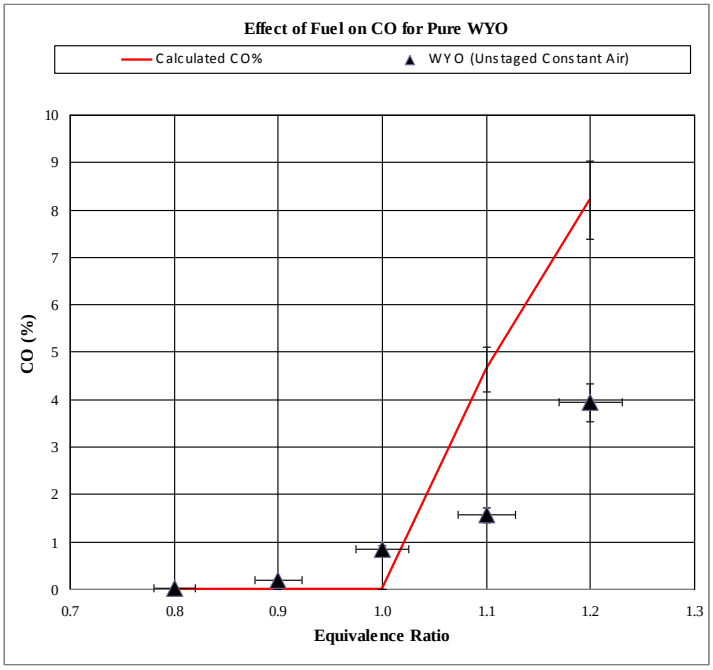

Figure 46. Calculated CO (%) compared to actual CO (%) emissions for unstaged WYO with constant air.

Based on the comparisons above, the measured results for CO are well within the estimated emission values calculated for the lean regions but almost 50% lower than the estimated values in the rich regions at their respective equivalence ratios. The measured values of CO_2 are greater than the estimated values in the rich region. Both of these discrepancies are due to the assumptions used for calculating the estimated CO and CO_2 emissions which are based on all the hydrogen being converted to H_2O, all the oxygen reacting with carbon at stoichiometric and rich conditions, and all the carbon reacting with oxygen to form CO and CO_2 with no hydrocarbon formations. These assumptions are not fully valid and the estimated values are not accurate due to the fact that not all of the hydrogen is converted to H_2O. There are measured concentrations of hydrocarbons during these experiments; therefore, some of the remaining hydrogen forms H_2 and does not react with oxygen. The oxygen is then free to react with CO to create additional CO_2. At stoichiometric conditions, there is a small amount of oxygen in the exhaust gas stream. The unstaged pure WYO with constant air was fired at stoichiometric conditions yielding the following exhaust gas concentrations: 0.60% O_2, 0.84% CO, 19.11% CO_2, 357 ppm of NO_x, and 10 ppm of C_xH_y shown in figure 47 below.

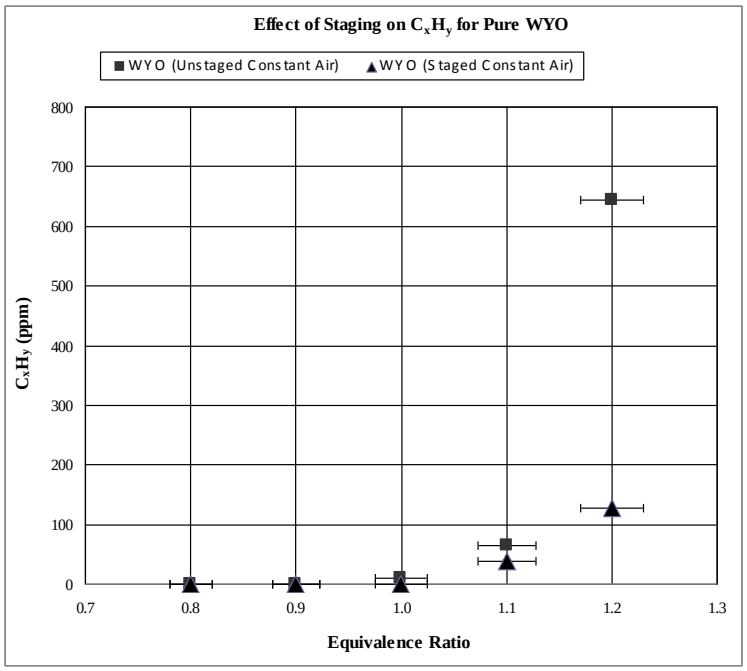

Figure 47. Hydrocarbon emissions for unstaged and staged WYO with constant air.

Since all the hydrogen does not react with oxygen to form H_2O during actual combustion, there is more oxygen available to react with CO and convert it to CO_2. This will cause CO to decrease and CO_2 to increase in actual measurements as compared to the estimated values calculated above for rich conditions.

EFFECT OF AIR STAGING FOR PURE WYO WITH CONSTANT FUEL FEED RATE / HEAT OUTPUT OF 100,000 BTU/HR

The WYO was fired with staged air with a constant fuel feed rate / heat output of 100,000 BTU/hr. The total air used (which includes the primary, secondary and tertiary air for the staged combustion) at each equivalence ratio was kept the same as the total air used for the unstaged combustion experiments. The primary air flow was kept constant at 98.76 LPM (5.93m^3/hr or 7.02 kg/hr). The secondary air flow from the unstaged experiments was divided between the staged secondary air and tertiary air so that the combined staged primary and secondary air flows made up 80% of the theoretical air required at stoichiometric conditions. The following figure 48, figure 49, and figure 50 show the effects of staging pure WYO with constant fuel feed rate / heat output on NO_x, CO_2, and CO emissions:

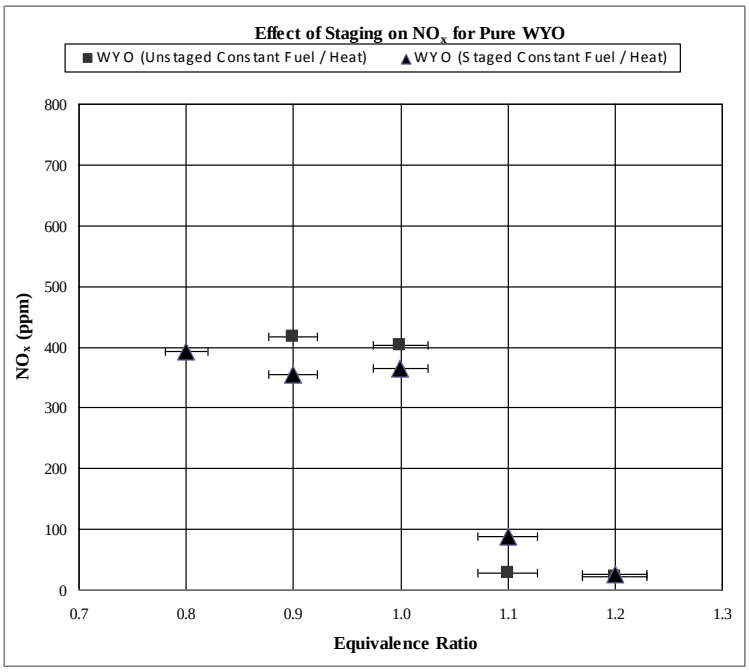

Figure 48. NO_x (ppm) emissions for pure WYO with constant fuel input / heat output of 100,000 BTU/hr.

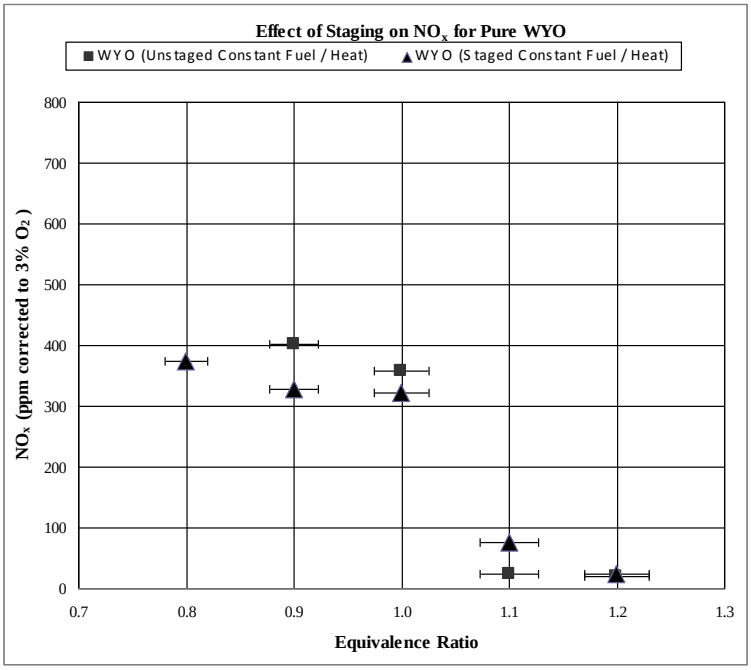

Figure 49. NO_x (ppm) emissions (corrected to 3% O_2) for pure WYO with constant fuel input / heat output of 100,000 BTU/hr.

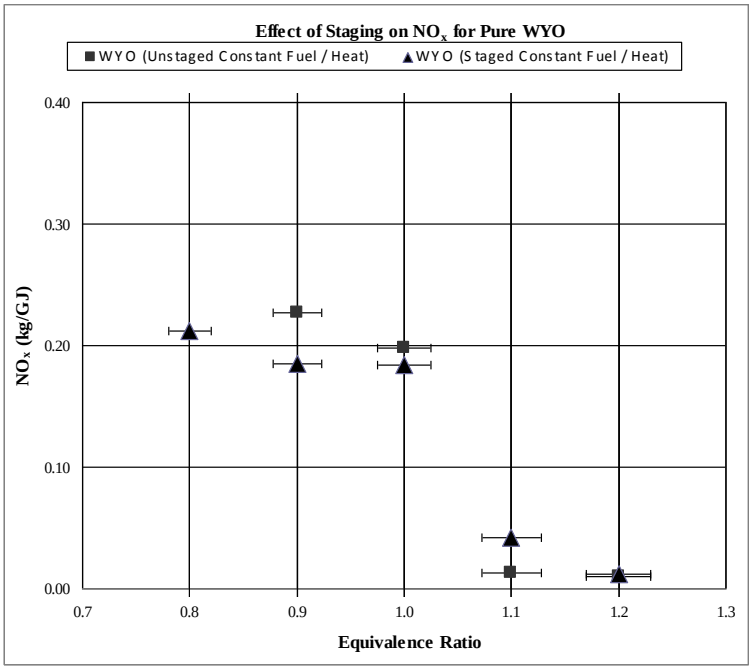

Figure 50. NO_x (kg/GJ) emissions for WYO:DB fuel blends with constant fuel input / heat output of 100,000 BTU/hr.

For the pure WYO with constant fuel feed rate / heat output fired in the LNB furnace, air staging caused a slight reduction in NO_x production for lean conditions while causing a slight increase in NO_x for rich conditions.

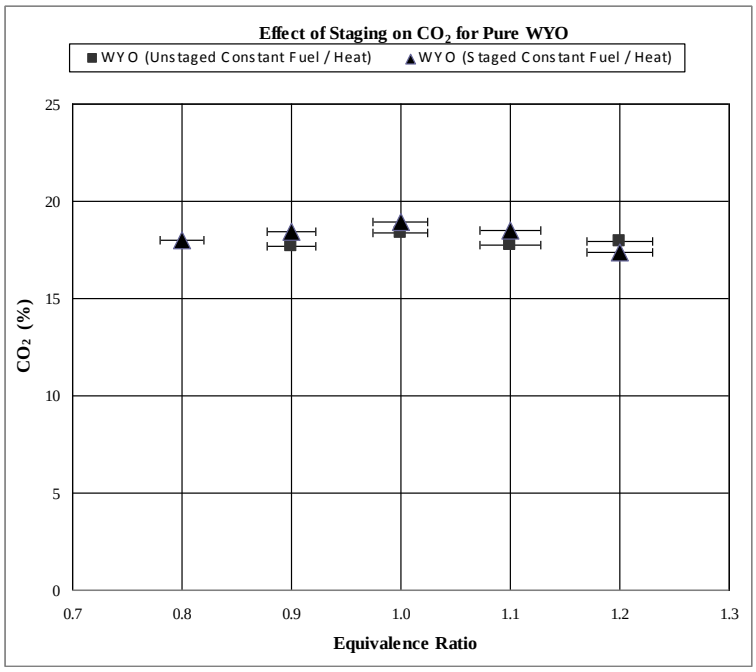

Figure 51. CO_2 (%) emissions for pure WYO with constant fuel input / heat output of 100,000 BTU/hr.

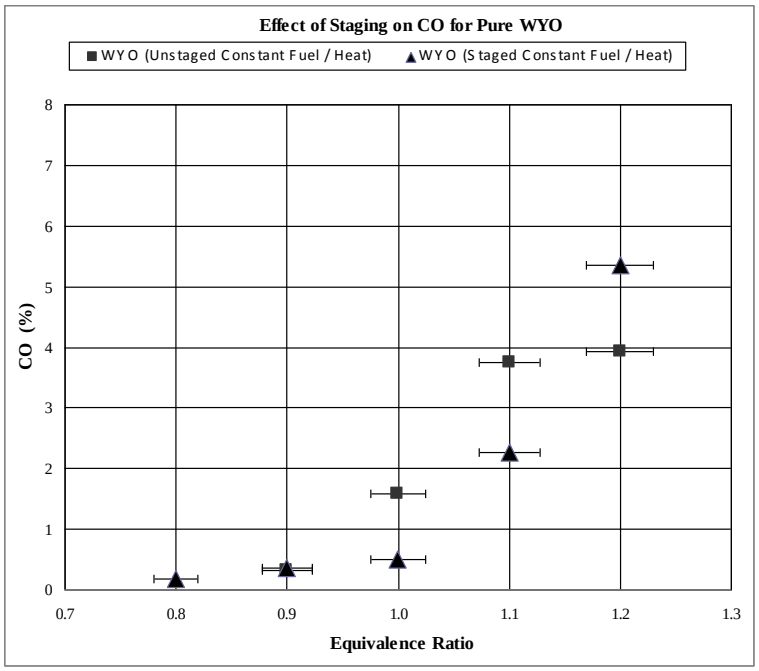

Figure 52. CO (%) emissions for pure WYO with constant fuel input / heat output of 100,000 BTU/hr.

Air staging had almost no effect on CO_2 emissions as shown in figure 51 above; however, staging caused a slight decrease of CO for $1 \leq \phi \leq 1.2$ but yielded a significant increase at $\phi = 1.2$ as shown in figure 52 above.

EFFECT OF AIR STAGING FOR PURE WYO WITH CONSTANT AIR FLOW

The WYO was then fired with staged air at a constant air flow set at stoichiometric air flow. The total air used (which includes the primary, secondary and tertiary air for the staged combustion) at each equivalence ratio was also kept the same as the total air used for unstaged experiments. The primary air flow was kept constant at 98.76 LPM (5.93 m^3/hr or 7.02 kg/hr). The secondary air flow was kept constant at 269.85 LPM (16.19 m^3/hr or 19.17 kg/hr) and the tertiary air was kept constant at 92.15 LPM (5.53 m^3/hr or 6.55 kg/hr). The fuel feed rate / heat output was adjusted to change the equivalence ratio required. The following figure 53, figure 54, and figure 55 show the effects of staging the pure WYO with a constant air flow on NO_x, CO_2 and CO emissions:

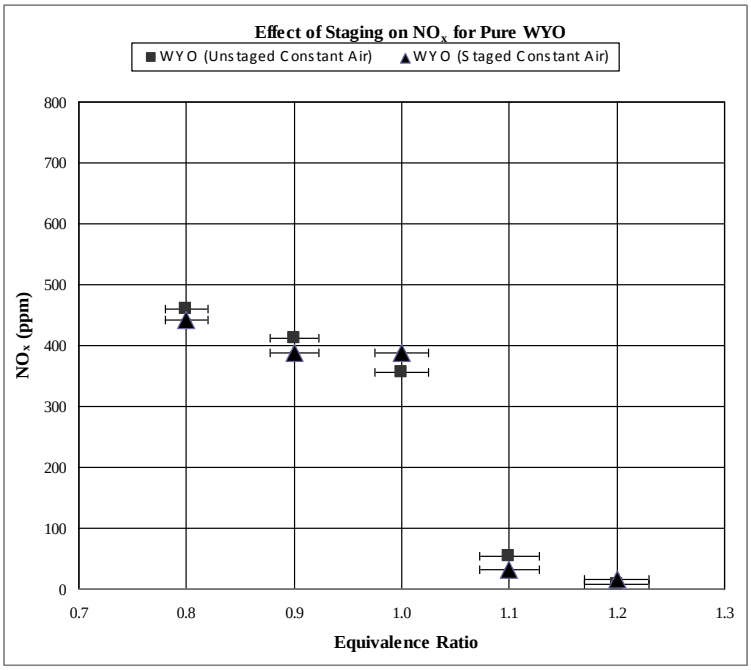

Figure 53. NO_x (ppm) emissions for pure WYO with constant air flow.

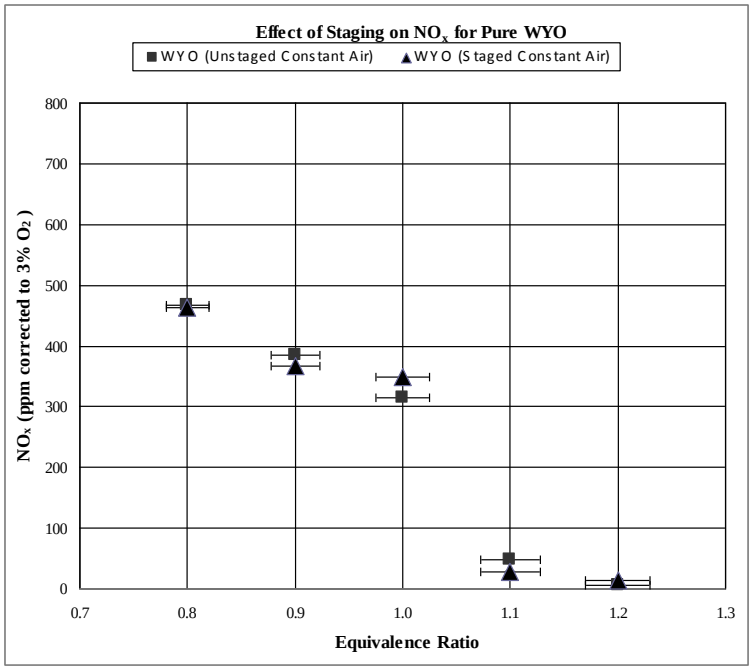

Figure 54. NO_x (ppm) emissions (corrected to 3% O_2) for pure WYO with constant air flow.

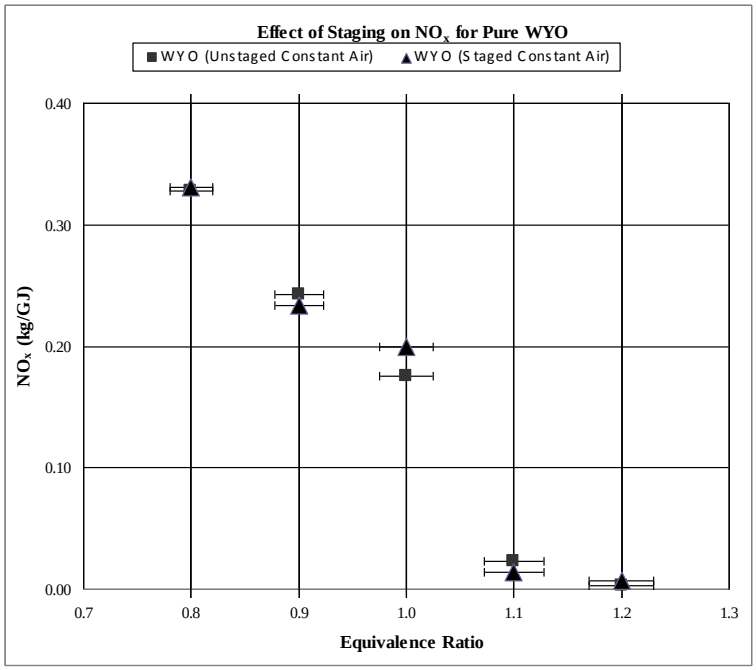

Figure 55. NO_x (kg/GJ) emissions for WYO:DB fuel blends with constant air flow.

For the pure WYO with constant air flow, air staging caused a slight reduction in NO_x production at stoichiometric conditions (ϕ = 1.0) while it yielded approximately the same NO_x concentration as unstaged combustion for rich conditions.

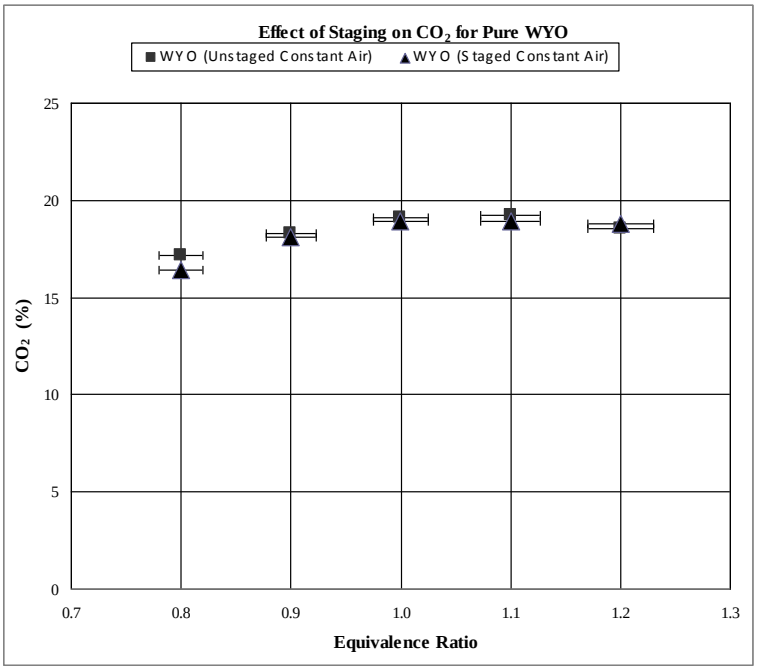

Figure 56. CO_2 (%) emissions for pure WYO with constant air flow.

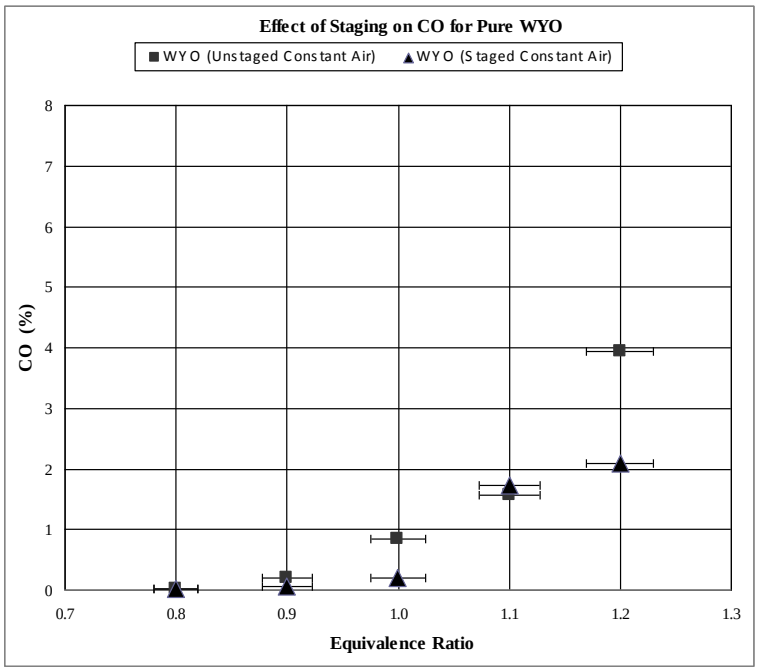

Figure 57. CO (%) emissions for pure WYO with constant air flow.

Air staging had little effect on CO_2 emissions but did cause a slight decrease of CO in very rich conditions ($\phi = 1.2$) as shown in figure 56 and figure 57.

EFFECT OF EQUIVALENCE RATIO FOR UNSTAGED WYO:DB FUEL BLENDS WITH CONSTANT FUEL FEED RATE / HEAT OUTPUT OF 100,000 BTU/HR

The equivalence ratio was varied from 0.8 to 1.2 in increments of 0.1 by adjusting the air flow with a constant fuel feed rate / heat output. The unstaged WYO was cofired with LA-PC-DB-SepS DB fuel blends with a constant fuel feed rate / heat output of 100,000 BTU/hr. The total air used includes only the primary and secondary air for unstaged combustion. The primary air flow was kept constant at 98.76 LPM

(5.93m^3/hr or 7.02 kg/hr). The secondary air flow was adjusted to vary the equivalence ratios. The following figures show the effects of equivalence ratio for unstaged WYO and WYO:DB fuel blends with constant fuel feed rate / heat output on NO_x, CO_2 and CO emissions:

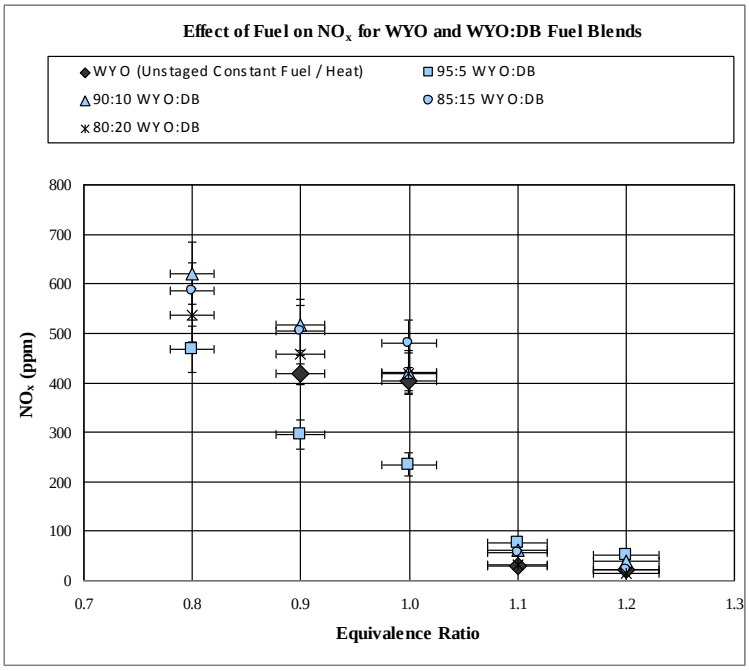

Figure 58. NO_x (ppm) emissions for unstaged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

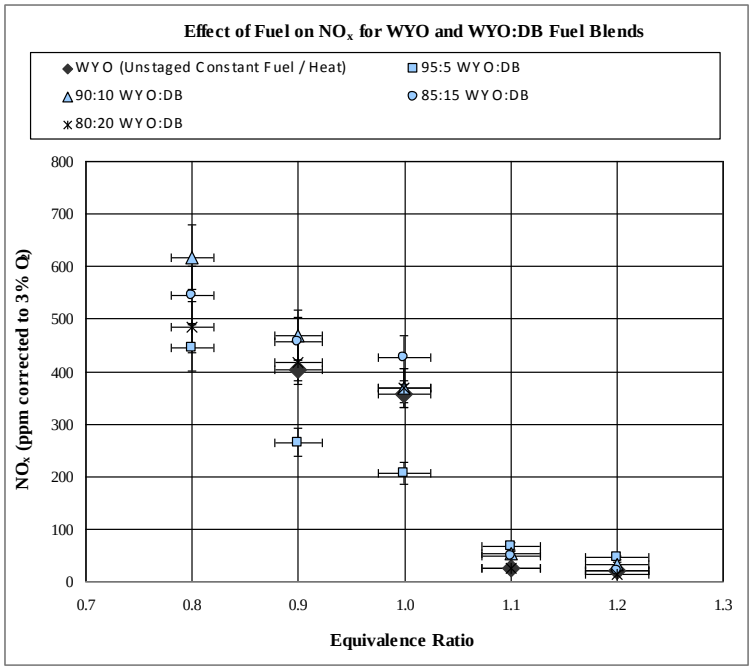

Figure 59. NO_x (ppm) emissions (corrected to 3% O_2) for unstaged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

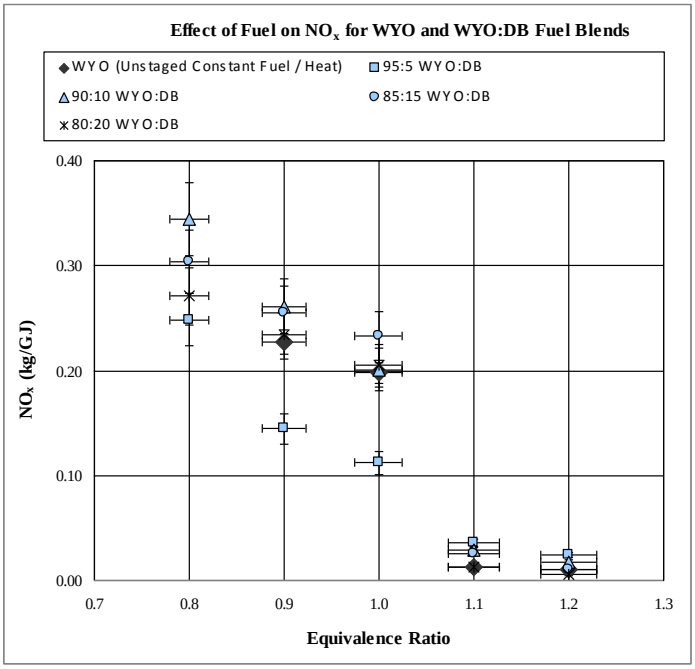

Figure 60. NO_x (kg/GJ) emissions for unstaged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

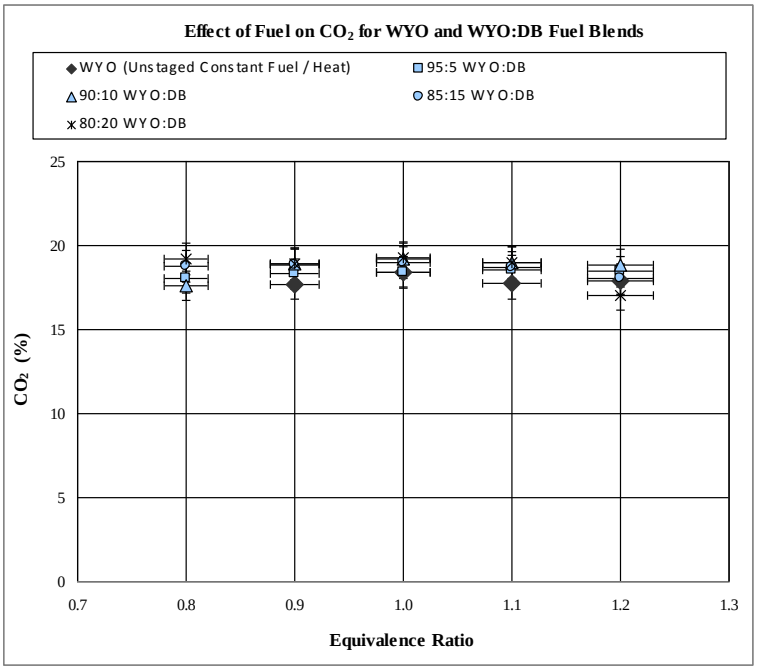

Figure 61. CO_2 (%) emissions for unstaged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

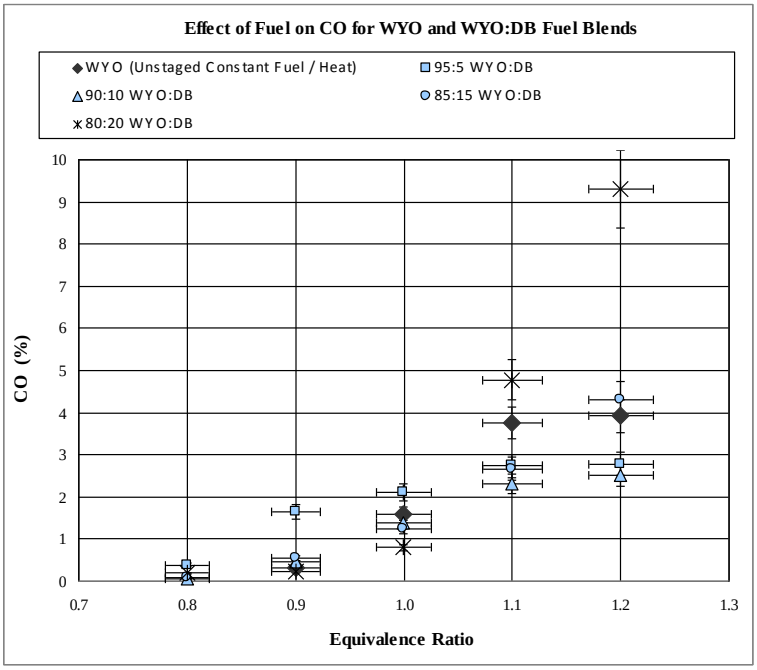

Figure 62. CO (%) emissions for unstaged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

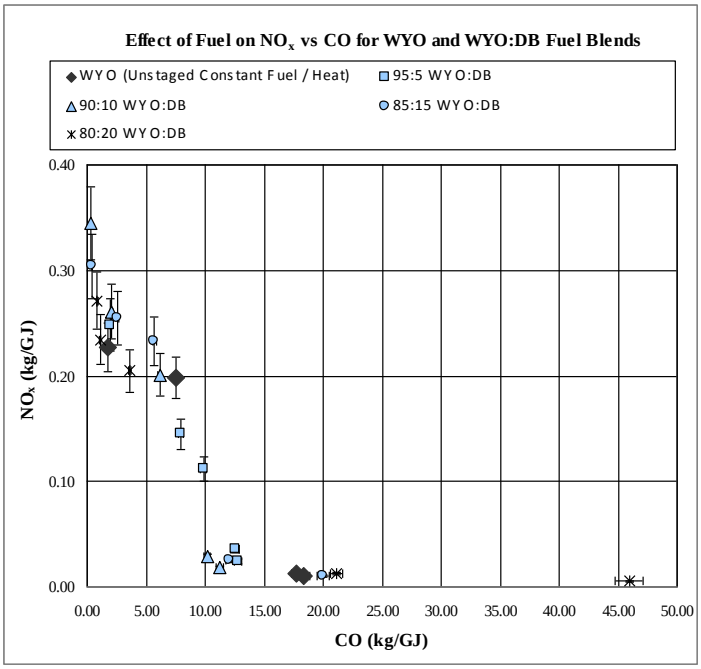

Figure 63. NO_x (kg/GJ) vs. CO (kg/GJ) for unstaged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

Cofiring the WYO with the LA-PC-DB-SepS shows increased NO_x production in the lean regions for most fuel blends as shown in figure 58, figure 59, and figure 60. At $\phi = 1.0$, the 80:20 blend seems to yield low NO_x which is a similar result for the constant air flow experiments conducted during this research. Cofiring the different fuel blends and changing the equivalence ratios seem to have no significant effect on CO_2 production (Figure 61). Cofiring seems to have a greater affect on NO_x in rich regions as opposed to the constant air flow case. Cofiring the 80:20 also seems to produce a significant increase in CO emissions in the rich region while the remaining fuel blends seem to produce a slight decrease as compared to the pure WYO (Figure 62). Decreasing NO_x emissions results in an increase of CO production (Figure 63).

In order to determine why the blends cause a change in NO_x as compared to pure WYO, temperature profiles were taken for the pure WYO and the fuel blends to see if there were any temperature differences that may have caused the lower NO_x production in the lean region as shown in figure 64 below.

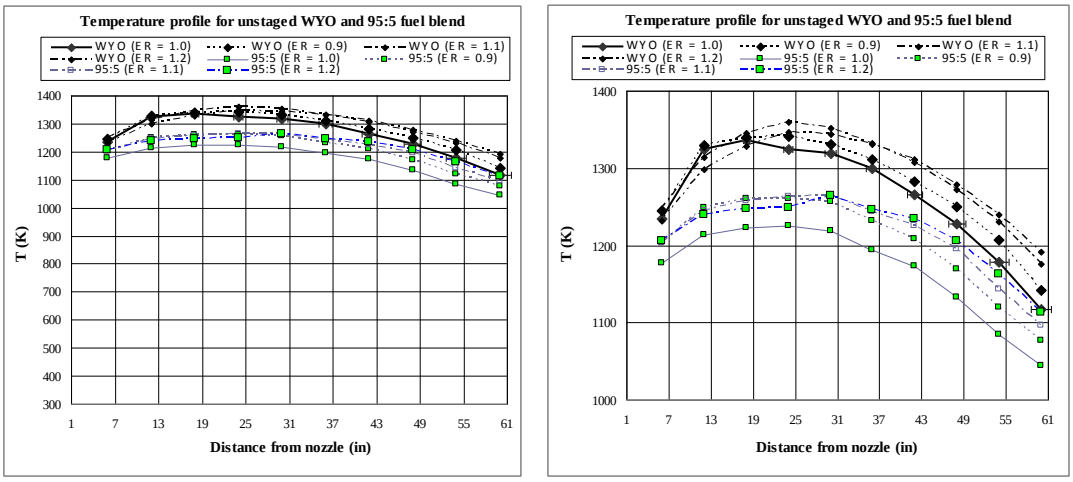

Figure 64. Temperature profile along the vertical length of the furnace of the unstaged WYO and unstaged 95:5 WYO:DB fuel blend.
(Figure A: Normal view; Figure B: Expanded view)

Based on the temperature profiles along the vertical length of the furnace, several experiments conducted with the WYO:DB fuel blends resulted in temperatures that were approximately 30 to 90 K lower than the temperatures of the pure WYO. Fuel NO_x is almost temperature insensitive compared to thermal NO_x.

EFFECT OF AIR STAGING FOR WYO:DB FUEL BLENDS WITH CONSTANT FUEL FEED RATE / HEAT OUTPUT OF 100,000 BTU/HR

The total air used includes the primary, secondary and tertiary air for staged combustion. The primary air flow was kept constant at 98.76 LPM (5.93m^3/hr or 7.02 kg/hr). The secondary air flow was kept constant with a flow rate that when added to primary air totaled approximately 80% of the theoretical air required at stoichiometric conditions. The equivalence ratio was also varied from 0.8 to 1.2 in increments of 0.1 by adjusting the tertiary air flow with a constant fuel feed rate / heat output. The staged WYO was cofired with LA-PC-DB-SepS with a constant fuel feed rate / heat output of 100,000 BTU/hr.

Figure 65, figure 66 and figure 67 show the NO_x emissions for staged WYO:DB fuel blends with constant fuel feed rate / heat output. Figure 68 and figure 69 show the effects of equivalence ratio for the staged WYO and WYO:DB fuel blends with a constant fuel feed rate / heat output on NO_x, CO_2, and CO emissions.

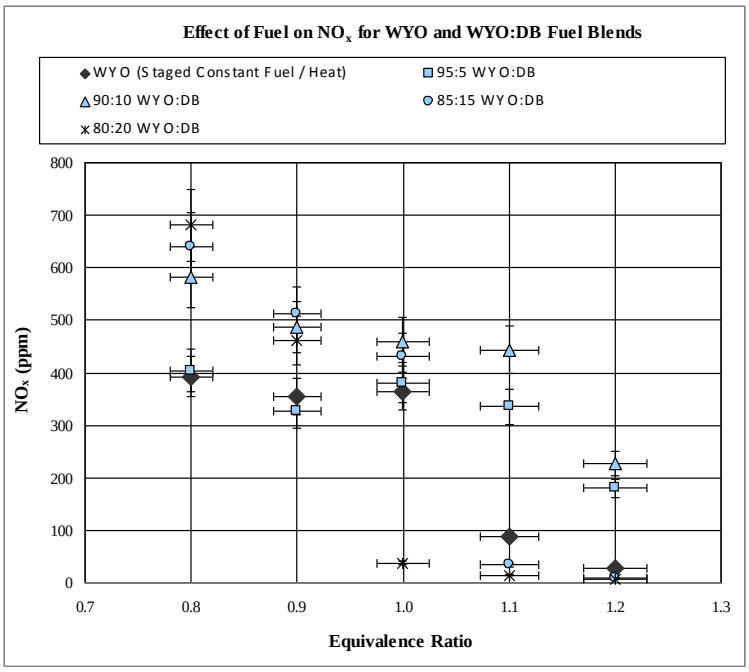

Figure 65. NO_x (ppm) emissions for staged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

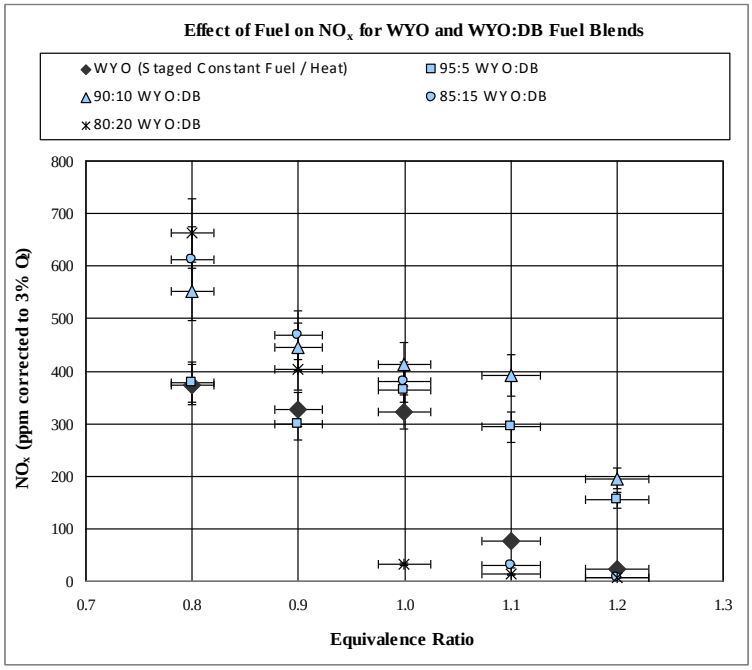

Figure 66. NO_x (ppm) emissions (corrected to 3% O_2) for staged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

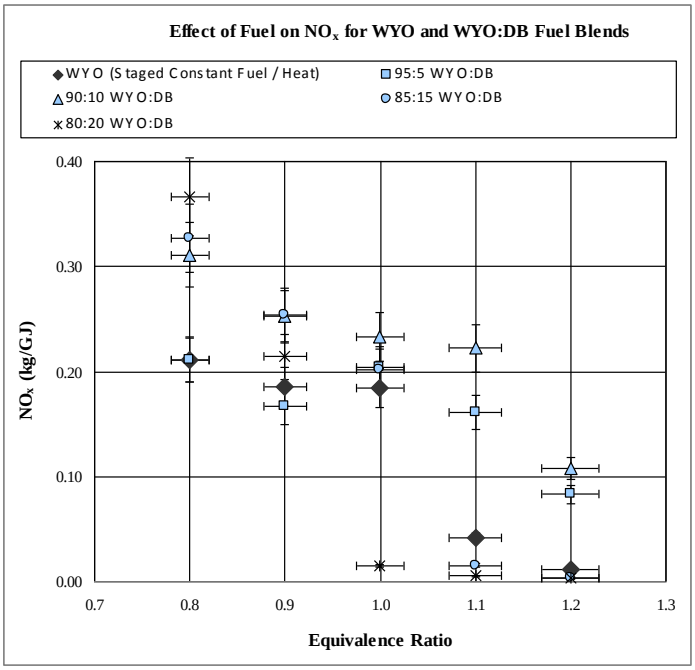

Figure 67. NO_x (kg/GJ) emissions for staged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

It is apparent that the 80:20 fuel blend yields the lowest NO_x for equivalence ratios between 1 and 1.2; however, this fuel blend yields the highest NO_x at $\phi = 0.8$. Most other fuel blends seem to increase NO_x in both the rich and lean regions.

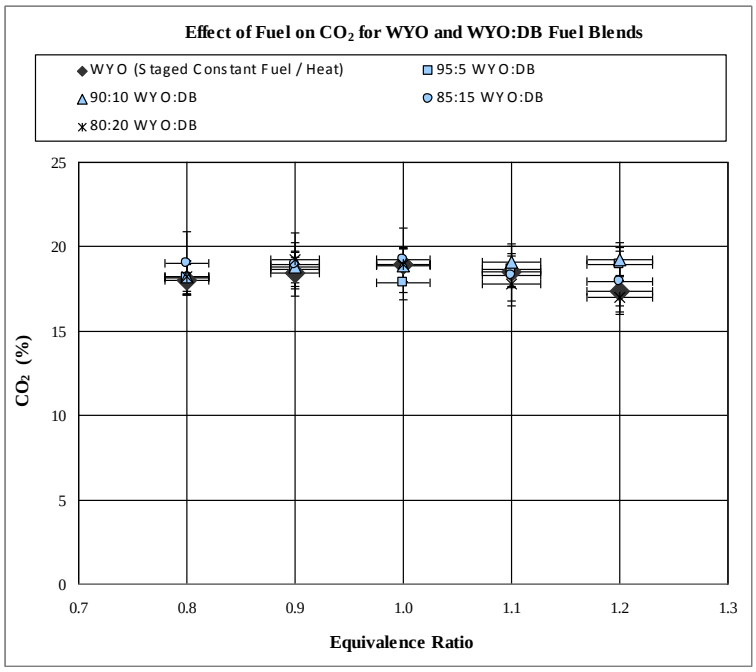

Figure 68. CO_2 (%) emissions for staged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

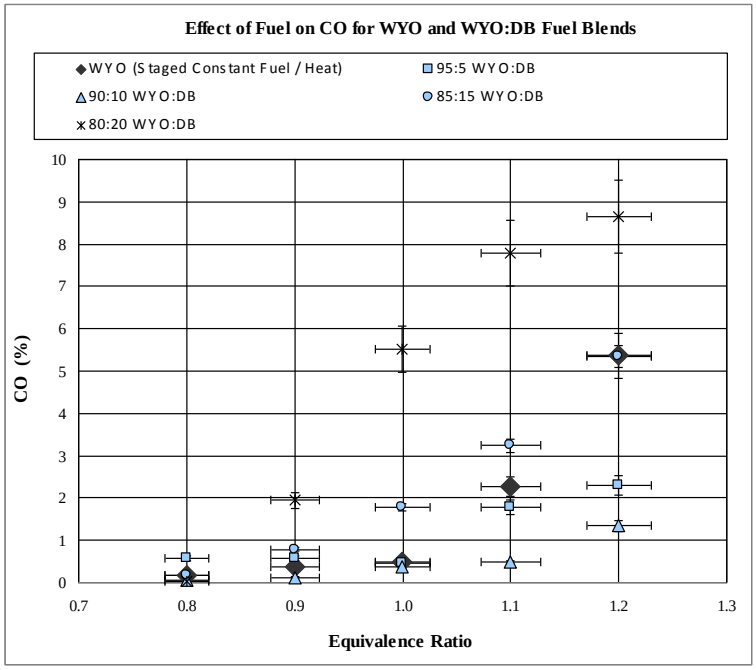

Figure 69. CO (%) emissions for staged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

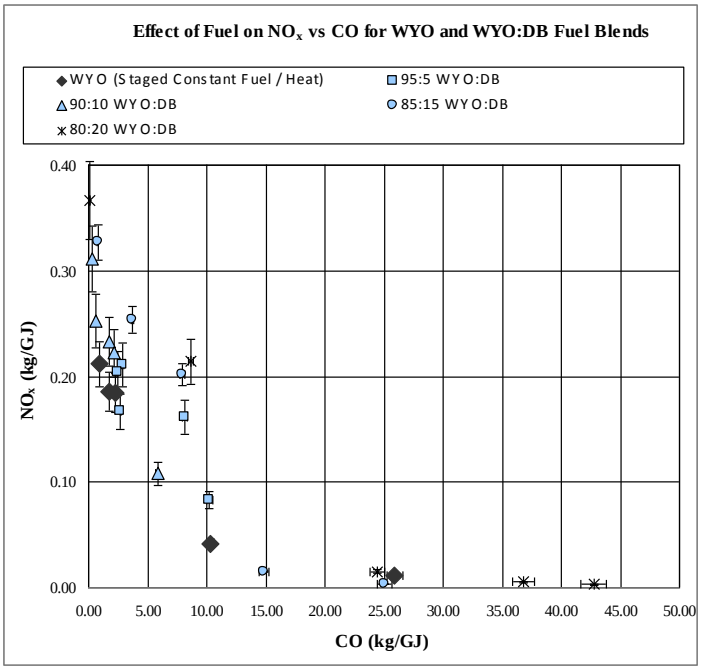

Figure 70. NO_x (kg/GJ) vs. CO (kg/GJ) for staged WYO:DB fuel blends with constant fuel feed rate / heat output of 100,000 BTU/hr.

Based on these exhaust measurements, cofiring the WYO:DB fuel blends caused the NO_x to increase in both the lean and rich regions when compared to the pure staged WYO (Figure 70). Staging caused a reduction in NO_x emissions in the lean region for pure WYO and the 90:10 WYO:DB fuel blends; however, for the 80:20 WYO:DB fuel blends, NO_x production actually increased as compared to unstaged combustion.

EFFECT OF EQUIVALENCE RATIO FOR WYO:DB FUEL BLENDS WITH CONSTANT AIR FLOW

During this set of experiments, the equivalence ratio was changed by changing the fuel feed rate / heat output for unstaged WYO:DB fuel blends while maintaining a

constant air flow consisting of primary and secondary air flows only. The following figure 71, figure 72, and figure 73 show the effects of equivalence ratio for unstaged WYO and WYO:DB fuel blends with a constant air flow on NO_x, CO_2 and CO emissions:

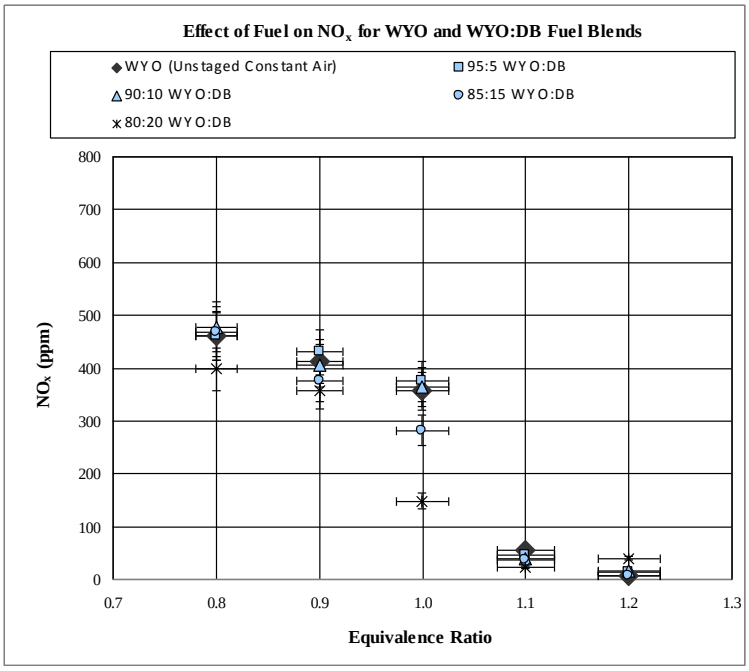

Figure 71. NO_x (ppm) emissions for unstaged WYO:DB fuel blends with constant air flow.

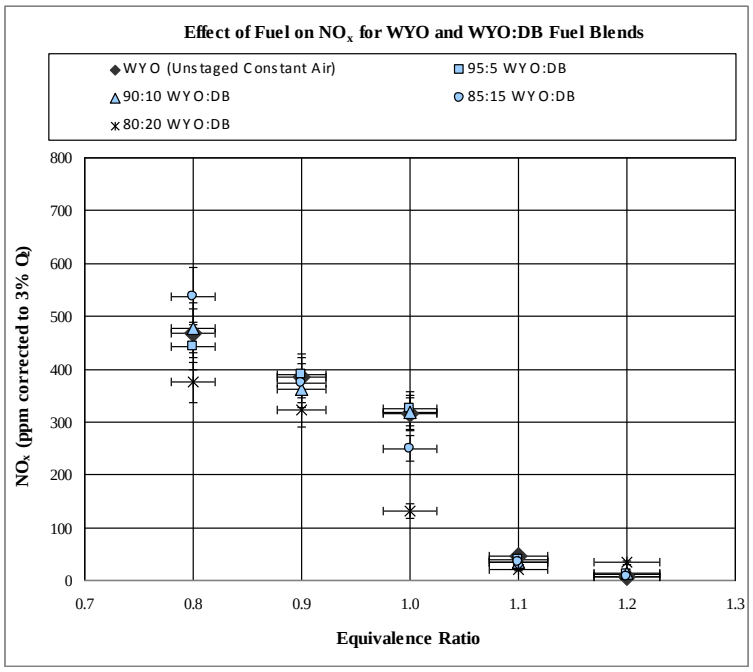

Figure 72. NO_x (ppm) emissions (corrected to 3% O_2) for unstaged WYO:DB fuel blends with constant air flow.

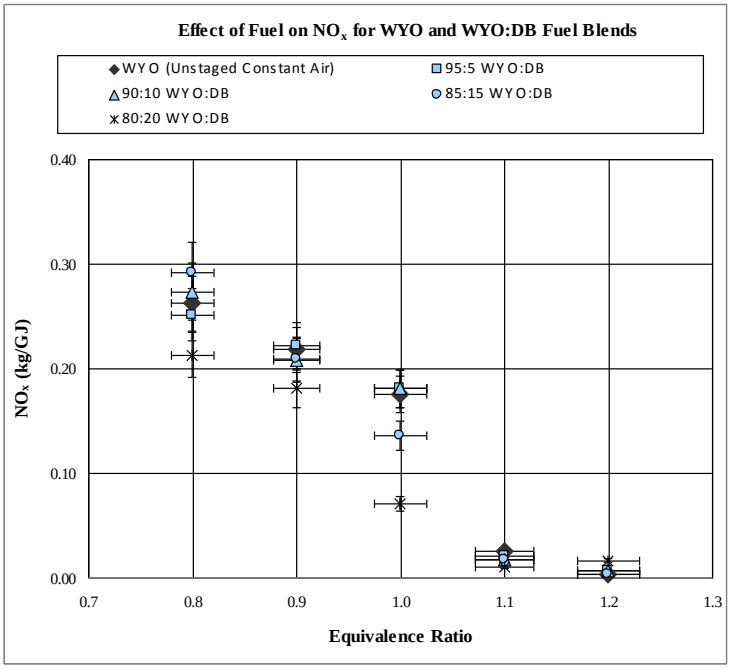

Figure 73. NO_x (kg/GJ) emissions for unstaged WYO:DB fuel blends with constant air flow.

Similar to the constant fuel feed rate / heat output case, the 80:20 fuel blend with constant air yields lower values of NO_x at stoichiometric and rich conditions.

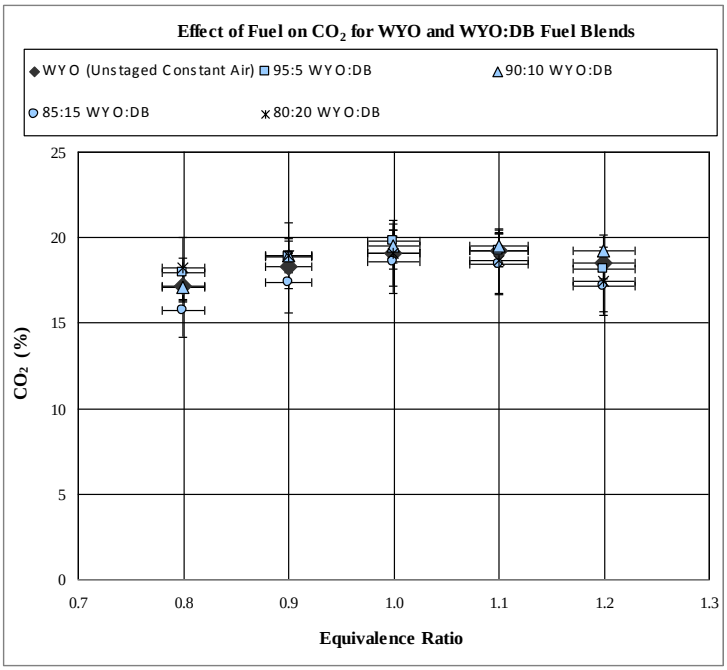

Figure 74. CO_2 (%) emissions for unstaged WYO:DB fuel blends with constant air flow.

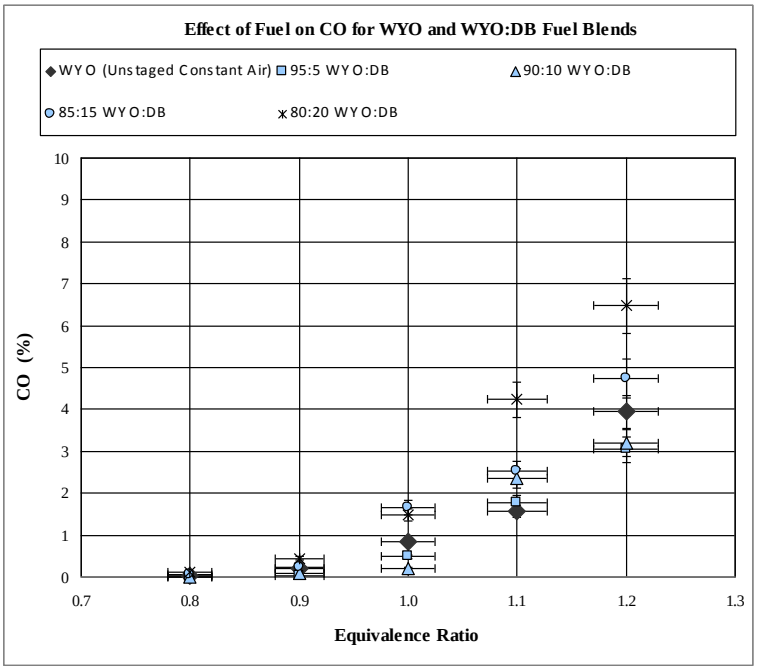

Figure 75. CO (%) emissions for unstaged WYO:DB fuel blends with constant air flow.

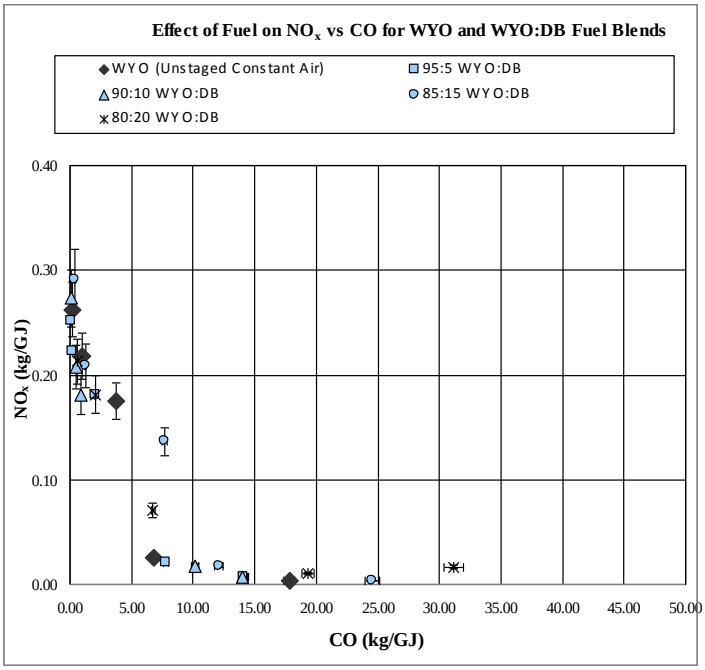

Figure 76. NO_x (kg/GJ) vs. CO (kg/GJ) for unstaged WYO:DB fuel blends with constant air flow.

Unstaged cofiring produced little effect on CO_2 emissions (Figure 74). As was the case with the constant fuel feed rate / heat output case, the unstaged 80:20 fuel blend with constant air yields the highest CO in the rich region (Figure 75). Figure 76 shows the effect of reducing NO_x emissions on CO emissions.

EFFECT OF AIR STAGING FOR WYO:DB FUEL BLENDS WITH CONSTANT AIR FLOW

For staged combustion, the total air (which includes primary, secondary and tertiary air) consisted of primary air flow that was kept constant at 98.76 LPM (5.93m^3/hr or 7.02 kg/hr) and secondary air flow that was kept constant with a flow rate that when added to primary air totaled approximately 80% of the theoretical air required at stoichiometric conditions. The equivalence ratio was varied from 0.8 to 1.2 in increments of 0.1 by adjusting the fuel feed rate / heat output with a constant air flow. The following figure 77, figure 78, and figure 79 show the effects of equivalence ratio for the staged WYO and WYO:DB fuel blends with a constant air flow on NO_x, CO_2, and CO emissions:

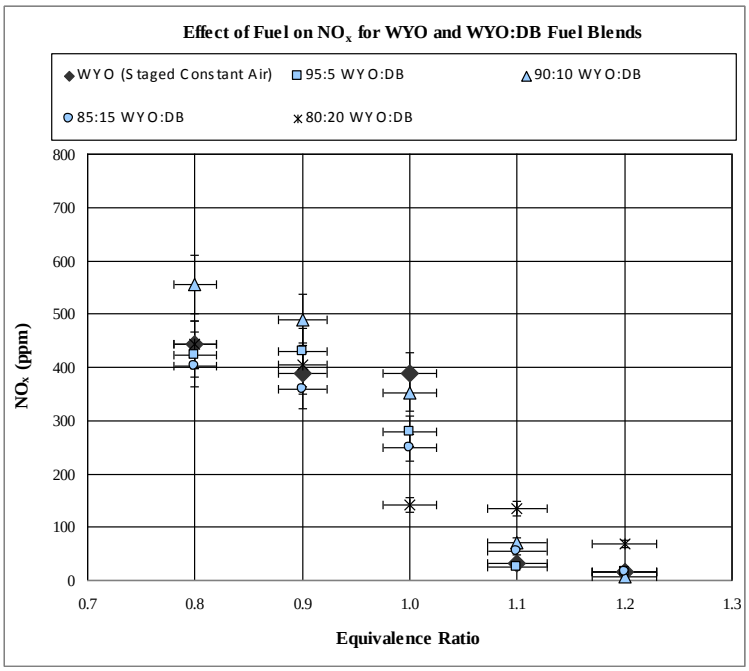

Figure 77. NO_x (ppm) emissions for staged WYO:DB fuel blends with constant air flow.

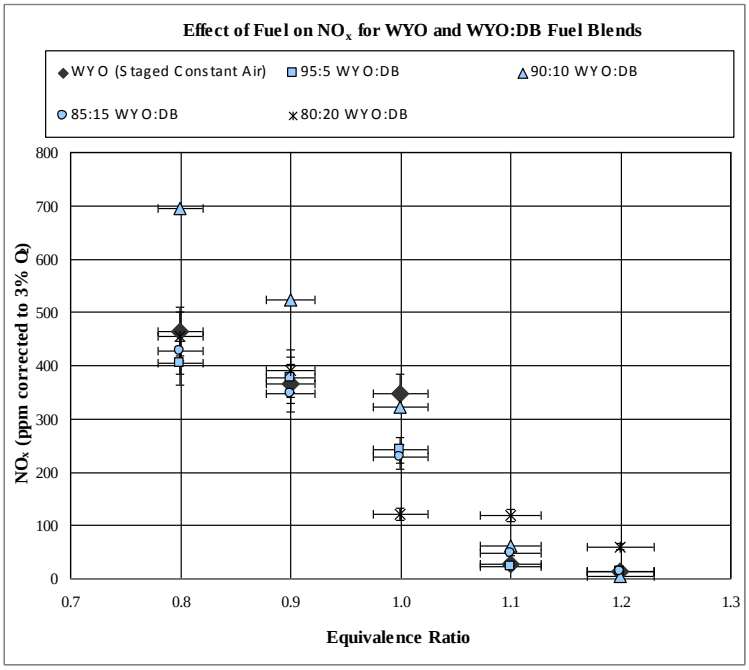

Figure 78. NO_x (ppm) emissions (corrected to 3% O_2) for staged WYO:DB fuel blends with constant air flow.

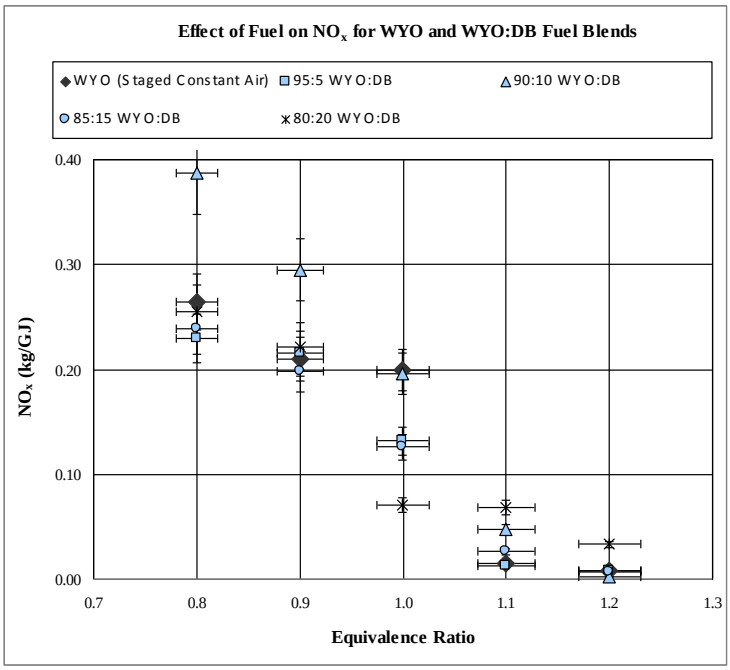

Figure 79. NO_x (kg/GJ) emissions for staged WYO:DB fuel blends with constant air flow.

As opposed to the unstaged constant air case, the 90:10 fuel blend yields higher NO_x in the lean regions while other fuel blends seem to yield approximately the same amount of NO_x using staged air in the LNB furnace.

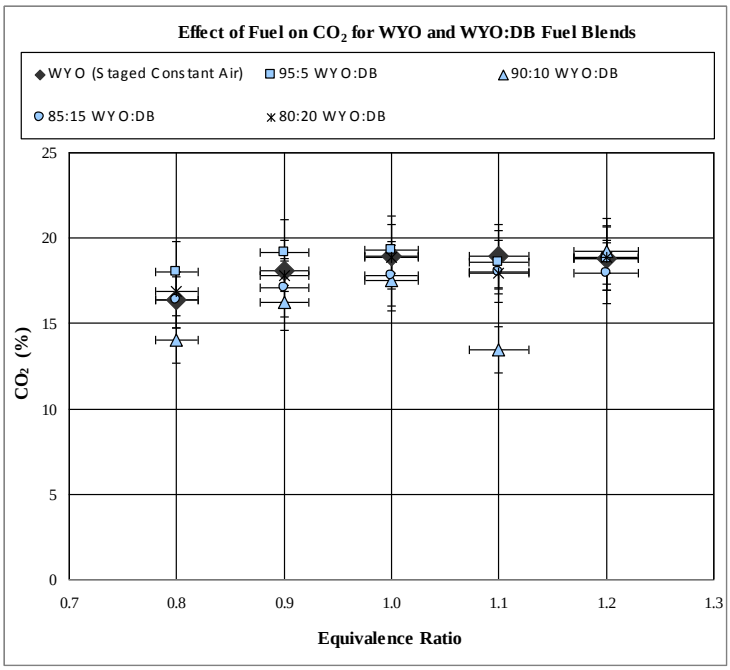

Figure 80. CO_2 (%) emissions for staged WYO:DB fuel blends with constant air flow.

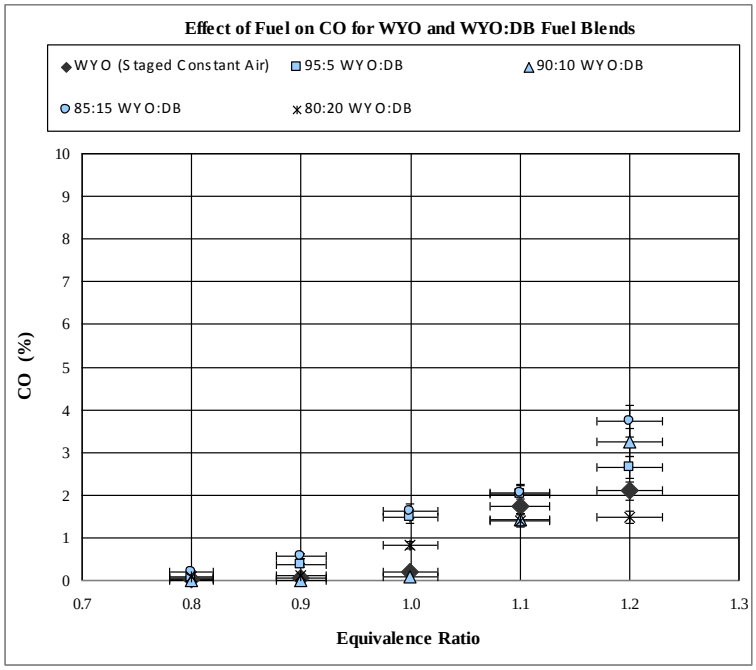

Figure 81. CO (%) emissions for staged WYO:DB fuel blends with constant air flow.

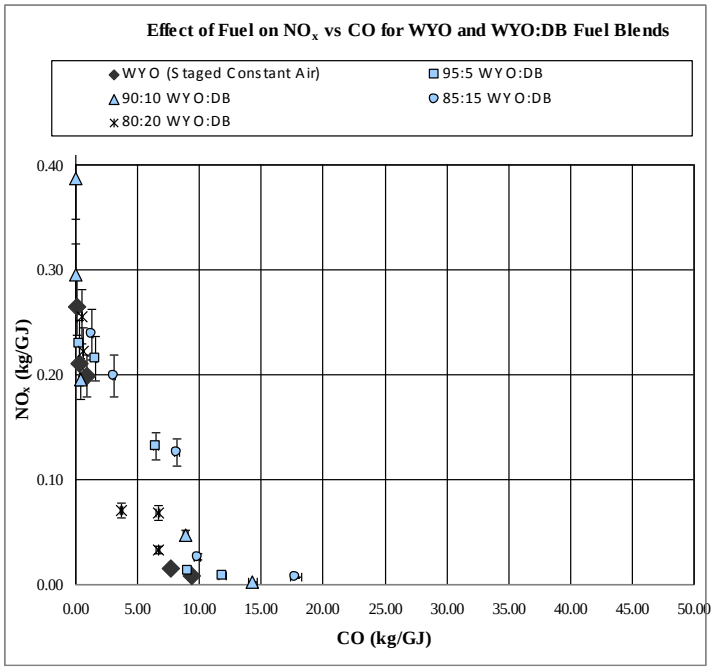

Figure 82. NO_x (kg/GJ) vs. CO (kg/GJ) for staged WYO:DB fuel blends with constant air flow.

Most staged fuel blends had little effect on CO_2 except for the 90:10 fuel blend which yielded lesser amounts of CO_2 emissions (Figure 80). As opposed to the constant fuel feed rate / heat output case, the 80:20 fuel blend seems to slightly increase NO_x while lowering CO emissions in the rich regions with the staged air. The constant air flow case seems to also yield lower CO since there is better mixing occurring than the constant fuel feed rate / heat output case (Figure 81). Figure 82 shows the effect of reducing NO_x emissions on CO emissions.

CONCLUSIONS

Based on current experiments using the 100,000 BTU/hr LNB furnace, air staging of the pure WYO produced some noticeable decrease in NO_x emissions for lean equivalence ratios greater than 1.0 while the following inverse relation between NO_x and CO emissions can be seen in the following figure 83:

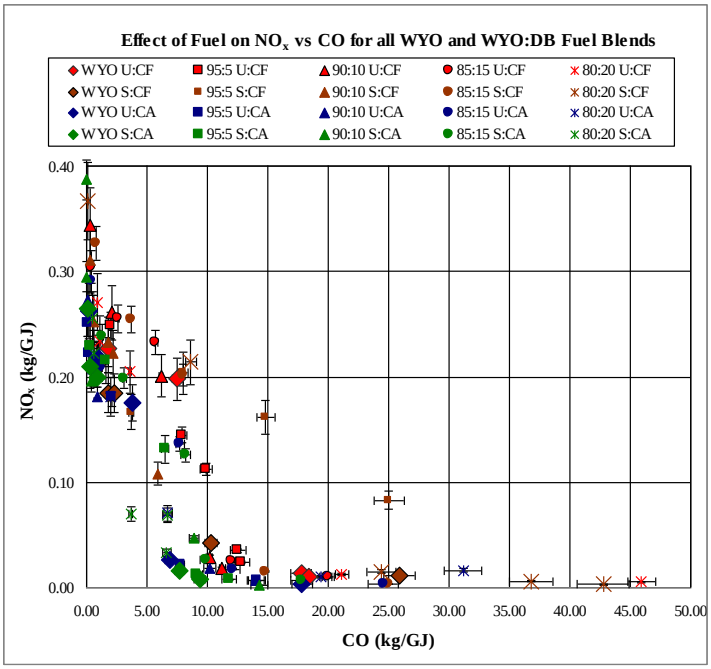

Figure 83. NO_x (kg/GJ) vs. CO (kg/GJ) for all WYO and WYO:DB fuel blend experiments.

CO_2 increases as NO_x emissions are decreased. The experiments with the constant fuel feed rate / heat output produced much higher concentrations of CO for pure WYO and 80:20 WYO:DB fuel blends than the experiments with the constant air flow. This may be a result of the better mixing which occurs with a constant primary, secondary and tertiary air flow. When the air flows are increased or decreased, this affects the mixing

pattern of the air which may result in less mixing reducing the amount of oxygen available to react with CO. This causes NO_x to decrease but causes CO concentrations to increase.

MIXING ANALYSIS RESULTS

To validate that the constructed furnace did behave as a LNB furnace which delayed or staged the air in the primary burn zone, the following cold experiment was conducted. Motive air, which carries the pulverized coal particles through the primary air flow line, is fixed at 70 SLPM (4.2 m^3/hr or 4.97 kg/hr) producing 98.76 SLPM (5.93 m^3/hr or 7.02 kg/hr) of total primary air and the secondary air is fixed at 278.55 SLPM (16.71 m^3/hr or 19.79 kg/hr). Approximately 94.33 LPM (5.66 m^3/hr or 6.7 kg/hr) of CO_2 was then supplied as the tertiary air for the equivalence ratios of 1.0 calculated for the pure WYO coal which required a total air flow of 471.64 LPM (28.3 m^3/hr or 33.51 kg/hr). The Greenline 8000 gas analyzer was then used to measure the CO_2 concentrations at the top sample port located 6 inches and 12 inches below the nozzle location to measure the percentage of CO_2 in the gas stream from the center of the burn chamber. The CO_2 concentration at 6 and 12 inches respectively was 12.49% and 12.54%. Since the CO_2 made up 20% of the total flow, then the measured values from the center location illustrated that only 62.45% of the CO_2 had mixed with the center 6 inches below the nozzle and 62.70% of the CO_2 had mixed with the center 12 inches below the nozzle indicating that there is no further mixing. Since 100% of the CO_2 did not mix with the center at these distances below the nozzle, the LNB nozzle successfully

staged the tertiary air (measured in the form of CO_2) and delayed complete mixing from occurring near the burner zone.

Although this test was conducted under cold conditions, the fact that the 100% of the CO_2 did not go directly to the center of the chamber based on using the same swirl lends support to the conclusion that with combustion, the tertiary air will also be delayed from reacting in the primary burn zone until it mixes in the secondary burn zone. Based on these results above that showed mixing was delayed, the staging effects of the nozzle were validated and the current nozzle design was used to conduct all LNB experiments using the pulverized WYO and dairy biomass fuel blends.

The mixing patterns will change during actual combustion due to the higher temperatures. The gases will all have lower densities which will increase axial speed; however, it is unknown as to whether the tangential speed will also be affected in the same manner and increase or if it will remain the same. If it remains the same, then mixing will be delayed even further due to the decreased residence time; however, if the tangential speed also increases then mixing should stay the same or increase when compared to the cold experiment conducted above.

CHAPTER VI

SUMMARY AND CONCLUSIONS

The major summary and conclusions of this research are as follows:

1. The LNB furnace construction was completed, and the LNB furnace successfully staged air during combustion of pure WYO and WYO:DB fuel blends.
2. Firing pure WYO with air staging caused approximately a 12% decrease of NO_x in lean regions and approximately a 24% increase of CO at ϕ=1.2.
3. There were minor differences on NO_x emissions based on the parametric studies involving adjusting the air flow while maintaining a constant fuel input or heat output of 100,000 BTU/hr when compared to adjusting the fuel input or heat output while maintaining a constant air flow; however, there was less CO for the constant air flow case showing that better mixing occurred for this case than in the constant fuel feed rate / heat output case.
4. LA-PC-DB-SepS was successfully blended with WYO for cofiring in a LNB furnace:
    a. For unstaged combustion for both the constant fuel feed rate/heat output cases and the constant air flow cases, cofiring resulted in most fuel blends producing similar NO_x emissions as the pure WYO at their respective equivalence ratios; however, due to the uncertainty of these experiments and the wide range of CO emissions measured, a

conclusion could not be determined for the effect of unstaged cofiring on CO.

b. Staged cofiring resulted in most fuel blends producing approximately a 33% increase of NO_x in the rich regions and while producing similar to slightly lower amounts of NO_x in the lean regions as compared to WYO.

c. The following correlation between NO_x and CO emissions was identified: As NO_x emissions decreased, CO emissions increased. This inverse relation was a main trend identified which held true for all WYO:DB fuel blends for both unstaged and staged conditions.

CHAPTER VII

FUTURE WORK

Future work that needs to be completed include the following:

1. Conduct additional experiments during actual combustion conditions to measure the mixing distance from the nozzle for the fuel to react with the tertiary air in order to validate that the LNB furnace stages the air as designed.
2. Conduct the same experiments completed in this research with the following modifications / additions:
    a. Measure the entrainment air flow to calculate a more accurate total primary air flow and reduce experimental uncertainty.
    b. Adjust the secondary air flow rates to vary the total percentage of primary and secondary air flow with respect to the total theoretical air flow required from a range of 65% to 85% to evaluate the optimum percentage required to achieve the lowest NO_x emissions for this LNB furnace design.
    c. Cofire TXL and LA-PC-DB-SepS biomass fuel blends to compare the effect of a different coal property utilized in the LNB furnace.
    d. Measure mercury emissions at various equivalence ratios and fuel blends to determine what if any impact the LNB furnace may have on mercury emissions.

e. Cofire biomass fuel blends with OFA to determine the net impact of the LNB furnace design and the addition of OFA on NO_x production.

3. Design various swirl blades with different swirl numbers to deduce the effect of swirl on NO_x production and flame stability.
4. Conduct experiments with constant air flow based on firing the base case coal, which in this research is pure WYO, at different equivalence ratios:
    a. Measure the O_2 % in the exhaust gas stream for each equivalence ratio ($\phi \leq 1.0$) for the base case coal.
    b. When switching to a different fuel or fuel blend:
        i. Maintain the same or constant air flow used for the base case coal;
        ii. For stoichiometric and lean equivalence ratios, adjust the fuel feed rate / heat output so that the O_2 % measured is equal to the oxygen concentration measured from the base case coal for that respective equivalence ratio: $\phi = 1.0$, $\phi = 0.9$, and $\phi = 0.8$.
        iii. Allow some time for the fuel feed rate and furnace temperatures to reach a steady rate.
        iv. Mount a humidity meter to measure relative humidity.

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APPENDIX A

The following section reports the burnt fraction, which approximates the percentage of combustibles that are burned, and the fuel nitrogen conversion efficiency.

The burnt fraction is approximated using the following equation from Annamalai et al. (2007):

$$BF = (1/\phi) * [1 - (X_{O2} / X_{O2,a})]$$

where,

ϕ - equivalence ratio

X_{O2} – O_2 mole fraction in exhaust gas stream

$X_{O2,a}$ – O_2 mole fraction in ambient air = 0.21

CONSTANT AIR				
% WYO:DB Fuel Blend	Equivalence Ratio	O_2 Mole Fraction	$O_{2,A}$ Mole Fraction	Burnt Fraction
WYO	0.8	0.0330	0.21	1.05
	0.9	0.0170	0.21	1.02
	1	0.0060	0.21	0.97
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
WYO Staged	0.8	0.0380	0.21	1.02
	0.9	0.0190	0.21	1.01
	1	0.0090	0.21	0.96
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
95:5 Unstaged	0.8	0.0230	0.21	1.11
	0.9	0.0110	0.21	1.05
	1	0.0020	0.21	0.99
	1.1	0.0010	0.21	0.90
	1.2	0.0000	0.21	0.83
95:5 Staged	0.8	0.0220	0.21	1.12
	0.9	0.0050	0.21	1.08
	1	0.0010	0.21	1.00
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
90:10 Unstaged	0.8	0.0300	0.21	1.07
	0.9	0.0090	0.21	1.06
	1	0.0040	0.21	0.98
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
90:10 Staged	0.8	0.0660	0.21	0.86
	0.9	0.0420	0.21	0.89
	1	0.0140	0.21	0.93
	1.1	0.0010	0.21	0.90
	1.2	0.0020	0.21	0.83
85:15 Unstaged	0.8	0.0530	0.21	0.93
	0.9	0.0290	0.21	0.96
	1	0.0070	0.21	0.97
	1.1	0.0110	0.21	0.86
	1.2	0.0120	0.21	0.79
85:15 Staged	0.8	0.0400	0.21	1.01
	0.9	0.0250	0.21	0.98
	1	0.0140	0.21	0.93
	1.1	0.0080	0.21	0.87
	1.2	0.0040	0.21	0.82
80:20 Unstaged	0.8	0.0190	0.21	1.14
	0.9	0.0100	0.21	1.06
	1	0.0070	0.21	0.97
	1.1	0.0030	0.21	0.90
	1.2	0.0000	0.21	0.83
80:20 Staged	0.8	0.0350	0.21	1.04
	0.9	0.0230	0.21	0.99
	1	0.0000	0.21	1.00
	1.1	0.0050	0.21	0.89
	1.2	0.0020	0.21	0.83

CONSTANT FUEL FEED RATE / HEAT OUTPUT				
% WYO:DB Fuel Blend	Equivalence Ratio	O_2 Mole Fraction	$O_{2,A}$ Mole Fraction	Burnt Fraction
WYO	0.8	N/A	0.21	N/A
	0.9	0.0230	0.21	0.99
	1	0.0070	0.21	0.97
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
WYO Staged	0.8	0.0210	0.21	1.13
	0.9	0.0150	0.21	1.03
	1	0.0060	0.21	0.97
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
95:5 Unstaged	0.8	0.0210	0.21	1.13
	0.9	0.0100	0.21	1.06
	1	0.0060	0.21	0.97
	1.1	0.0020	0.21	0.90
	1.2	0.0030	0.21	0.82
95:5 Staged	0.8	0.0180	0.21	1.14
	0.9	0.0130	0.21	1.04
	1	0.0220	0.21	0.90
	1.1	0.0040	0.21	0.89
	1.2	0.0000	0.21	0.83
90:10 Unstaged	0.8	0.0290	0.21	1.08
	0.9	0.0120	0.21	1.05
	1	0.0040	0.21	0.98
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
90:10 Staged	0.8	0.0200	0.21	1.13
	0.9	0.0130	0.21	1.04
	1	0.0100	0.21	0.95
	1.1	0.0060	0.21	0.88
	1.2	0.0010	0.21	0.83
85:15 Unstaged	0.8	0.0170	0.21	1.15
	0.9	0.0110	0.21	1.05
	1	0.0070	0.21	0.97
	1.1	0.0010	0.21	0.90
	1.2	0.0000	0.21	0.83
85:15 Staged	0.8	0.0220	0.21	1.12
	0.9	0.0130	0.21	1.04
	1	0.0050	0.21	0.98
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
80:20 Unstaged	0.8	0.0110	0.21	1.18
	0.9	0.0130	0.21	1.04
	1	0.0060	0.21	0.97
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83
80:20 Staged	0.8	0.0250	0.21	1.10
	0.9	0.0040	0.21	1.09
	1	0.0000	0.21	1.00
	1.1	0.0000	0.21	0.91
	1.2	0.0000	0.21	0.83

The fuel nitrogen conversion efficiency is based on the assumption that all NO_x emissions are formed from fuel NO_x. The following equation from Annamalai et al. (2007) was used to estimate the fuel nitrogen conversion efficiency for all cases:

$$N_{CONV} = (c/n)*X_{NO} / (X_{CO2} + X_{CO})$$

where,

c – carbon molal concentration based on fuel chemical empirical formula

n – nitrogen molal concentration based on fuel chemical empirical formula

X_{NO} – NO_x mole fraction in exhaust gas stream

X_{CO2} – CO_2 mole fraction in exhaust gas stream

X_{CO} – CO mole fraction in exhaust gas stream

CONSTANT AIR						
% WYO:DB Fuel Blend	Equivalence Ratio	X_{NO}	X_{CO}	X_{CO2}	c/n	N_{CONV} (%)
WYO	0.8	0.000460	0.00030	0.1714	82.20	22.02
	0.9	0.000412	0.00200	0.1831	82.20	18.30
	1	0.000357	0.00840	0.1911	82.20	14.71
	1.1	0.000055	0.01570	0.1924	82.20	2.17
	1.2	0.000008	0.03940	0.1854	82.20	0.29
WYO Staged	0.8	0.000443	0.00020	0.1639	82.20	22.19
	0.9	0.000389	0.00060	0.1808	82.20	17.63
	1	0.000389	0.00200	0.1892	82.20	16.72
	1.1	0.000033	0.01730	0.1893	82.20	1.31
	1.2	0.000017	0.02100	0.1882	82.20	0.67
95:5 Unstaged	0.8	0.000461	0.00010	0.1794	79.16	20.33
	0.9	0.000430	0.00040	0.1889	79.16	17.98
	1	0.000375	0.00480	0.1979	79.16	14.64
	1.1	0.000046	0.01770	0.1924	79.16	1.73
	1.2	0.000014	0.03050	0.1814	79.16	0.52
95:5 Staged	0.8	0.000423	0.00060	0.1800	79.16	18.54
	0.9	0.000430	0.00360	0.1918	79.16	17.42
	1	0.000280	0.01490	0.1933	79.16	10.65
	1.1	0.000026	0.02020	0.1857	79.16	1.00
	1.2	0.000017	0.02650	0.1880	79.16	0.63
90:10 Unstaged	0.8	0.000478	0.00010	0.1712	76.11	21.24
	0.9	0.000405	0.00100	0.1898	76.11	16.16
	1	0.000364	0.00210	0.1949	76.11	14.06
	1.1	0.000040	0.02360	0.1949	76.11	1.39
	1.2	0.000017	0.03210	0.1922	76.11	0.58
90:10 Staged	0.8	0.000555	0.00000	0.1405	76.11	30.07
	0.9	0.000489	0.00000	0.1623	76.11	22.93
	1	0.000352	0.00080	0.1752	76.11	15.22
	1.1	0.000072	0.01420	0.1345	76.11	3.69
	1.2	0.000006	0.03240	0.1920	76.11	0.20
85:15 Unstaged	0.8	0.000469	0.00050	0.1572	73.07	21.73
	0.9	0.000375	0.00220	0.1735	73.07	15.59
	1	0.000282	0.01660	0.1861	73.07	10.17
	1.1	0.000038	0.02520	0.1848	73.07	1.32
	1.2	0.000008	0.04740	0.1719	73.07	0.27
85:15 Staged	0.8	0.000403	0.00210	0.1636	73.07	17.77
	0.9	0.000358	0.00560	0.1709	73.07	14.82
	1	0.000250	0.01630	0.1783	73.07	9.39
	1.1	0.000054	0.02040	0.1804	73.07	1.96
	1.2	0.000015	0.03730	0.1796	73.07	0.51
80:20 Unstaged	0.8	0.000398	0.00120	0.1820	70.02	15.21
	0.9	0.000358	0.00440	0.1895	70.02	12.93
	1	0.000148	0.01480	0.1909	70.02	5.04
	1.1	0.000024	0.04230	0.1863	70.02	0.74
	1.2	0.000040	0.06470	0.1745	70.02	1.17
80:20 Staged	0.8	0.000443	0.00090	0.1691	70.02	18.25
	0.9	0.000405	0.00110	0.1778	70.02	15.85
	1	0.000141	0.00820	0.1886	70.02	5.02
	1.1	0.000135	0.01390	0.1798	70.02	4.88
	1.2	0.000069	0.01480	0.1890	70.02	2.37

CONSTANT FUEL FEED RATE / HEAT OUTPUT						
% WYO:DB Fuel Blend	Equivalence Ratio	X_{NO}	X_{CO}	X_{CO2}	c/n	N_{CONV} (%)
WYO	0.8	N/A	N/A	N/A	N/A	N/A
	0.9	0.000418	0.00330	0.1770	82.20	19.06
	1	0.000404	0.01590	0.1840	82.20	16.61
	1.1	0.000029	0.03750	0.1773	82.20	1.11
	1.2	0.000023	0.03920	0.1793	82.20	0.87
WYO Staged	0.8	0.000393	0.00180	0.1802	82.20	17.75
	0.9	0.000355	0.00360	0.1843	82.20	15.53
	1	0.000365	0.00500	0.1892	82.20	15.45
	1.1	0.000089	0.02270	0.1850	82.20	3.52
	1.2	0.000027	0.05360	0.1736	82.20	0.98
95:5 Unstaged	0.8	0.000468	0.00390	0.1806	79.16	20.08
	0.9	0.000295	0.01650	0.1831	79.16	11.70
	1	0.000235	0.02110	0.1844	79.16	9.05
	1.1	0.000077	0.02740	0.1853	79.16	2.87
	1.2	0.000052	0.02780	0.1846	79.16	1.94
95:5 Staged	0.8	0.000404	0.00570	0.1818	79.16	17.06
	0.9	0.000327	0.00570	0.1864	79.16	13.47
	1	0.000381	0.00470	0.1785	79.16	16.46
	1.1	0.000336	0.01780	0.1863	79.16	13.03
	1.2	0.000180	0.02310	0.1893	79.16	6.71
90:10 Unstaged	0.8	0.000621	0.00060	0.1760	76.11	26.76
	0.9	0.000516	0.00450	0.1892	76.11	20.28
	1	0.000422	0.01390	0.1919	76.11	15.61
	1.1	0.000062	0.02300	0.1899	76.11	2.22
	1.2	0.000039	0.02520	0.1883	76.11	1.39
90:10 Staged	0.8	0.000582	0.00060	0.1826	76.11	24.18
	0.9	0.000488	0.00120	0.1883	76.11	19.60
	1	0.000459	0.00380	0.1891	76.11	18.11
	1.1	0.000444	0.00480	0.1910	76.11	17.26
	1.2	0.000227	0.01340	0.1925	76.11	8.39
85:15 Unstaged	0.8	0.000585	0.00080	0.1877	73.07	22.68
	0.9	0.000505	0.00560	0.1884	73.07	19.02
	1	0.000480	0.01250	0.1896	73.07	17.35
	1.1	0.000056	0.02670	0.1872	73.07	1.91
	1.2	0.000023	0.04300	0.1802	73.07	0.75
85:15 Staged	0.8	0.000640	0.00160	0.1902	73.07	24.38
	0.9	0.000512	0.00780	0.1896	73.07	18.95
	1	0.000432	0.01780	0.1921	73.07	15.04
	1.1	0.000034	0.03240	0.1832	73.07	1.15
	1.2	0.000009	0.05350	0.1796	73.07	0.28
80:20 Unstaged	0.8	0.000536	0.00190	0.1920	70.02	19.36
	0.9	0.000458	0.00230	0.1894	70.02	16.73
	1	0.000419	0.00800	0.1927	70.02	14.62
	1.1	0.000031	0.04770	0.1897	70.02	0.91
	1.2	0.000015	0.09310	0.1703	70.02	0.40
80:20 Staged	0.8	0.000681	0.00020	0.1820	70.02	26.17
	0.9	0.000462	0.01940	0.1923	70.02	15.28
	1	0.000038	0.05510	0.1897	70.02	1.09
	1.1	0.000015	0.07790	0.1779	70.02	0.41
	1.2	0.000008	0.08650	0.1700	70.02	0.22

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